ENERGY REPORT:
Industry Facts and Updates

to the
Regulatory Flexibility Committee

of the
Indiana General Assembly

by the
Indiana Utility Regulatory Commission

October 1997

Chairman William D. McCarty
Commission Mary Jo Huffman
Commissioner G. Richard Klein
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I. PURPOSE AND SCOPE OF THE REPORT

The report outlines the status of competition in the Indiana energy utility industry, both electric and gas. The report reviews the activities of the energy industry in Indiana and provides an update of facts and developments since the Indiana Utility Regulatory Commission's 1996 Energy Report.[1] It also looks at competition initiatives in other states and at the federal level. The report is intended to satisfy the requirements of I.C. 8-1-2.5-9(b).

II. EXECUTIVE SUMMARY

Indiana Energy Industry Structure and Prices

The type of electric utility that is most significant in terms of generation and customers served is the investor-owned (IOU). Five major investor-owned utilities operate within the state: Indianapolis Power & Light (IPL), Indiana Michigan Power (I&M), Northern Indiana Public Service (NIPSCO), PSI Energy (PSI) and Southern Indiana Gas & Electric (SIGECO). Most IOUs are vertically integrated, meaning they own facilities for generation, transmission and distribution (T&D). IOUs are typically able to generate enough power for their own requirements and produce power for sale in the wholesale market.

There are 78 municipally owned electric utilities in Indiana, 34 of which are regulated by the Indiana Utility Regulatory Commission (IURC or the Commission). Municipal utilities typically own very little, if any, generating capacity; they purchase electricity from other sources and resell it to their retail customers. Many municipals in the state are members of the Indiana Municipal Power Agency (IMPA). IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power.

Forty-three nonprofit electric distribution cooperatives exist in Indiana, of which 14 have opted out of Commission jurisdiction. They generally purchase electricity at wholesale rates rather than owning generation facilities. Within Indiana, there are two generation and transmission (G&T) cooperatives: Hoosier Energy and Wabash Valley Power Association. These G&T cooperatives serve as coordinators of bulk power supplies and transmission services for their members.

Data from the Energy Information Administration (EIA) for 1995 show that Indiana had the eighth lowest average revenue per kilowatt-hour. The less-expensive western states have the advantage of hydropower and abundant coal reserves, while Tennessee has the Tennessee Valley

[1] Energy Report, Indiana Utility Regulatory Commission, October 1, 1996.

Authority (TVA) to provide low-cost power. Kentucky has access to both plentiful coal supplies and some TVA power. Indiana's favorable ranking comes from not only its coal reserves, but from depreciated plants and relatively little utility investment in expensive nuclear power.

In Indiana, there are three large investor-owned gas utilities, Indiana Gas, NIPSCO and SIGECO, and 17 smaller IOUs. The three largest IOUs are owned by holding companies, and two of them, NIPSCO and SIGECO, also operate major electric utilities. Gas IOUs, unlike their electric IOU counterparts, are not vertically integrated; they typically do not own gas production or pipeline facilities beyond their local distribution area.

There are 19 municipally owned gas utilities in Indiana, four of which are regulated by the IURC. The largest municipal gas utility in the state is Indianapolis-based Citizens Gas and Coke, which is regulated by the IURC. Like their IOU counterparts, municipal gas utilities serve as a "reseller" to their retail customers. Typically, municipal gas utilities purchase gas supply and transportation rights rather than having any ownership in production or interstate pipeline facilities.

According to the EIA, the average natural gas price to Indiana residential and commercial customers is below the national average.

Due to initiatives by FERC, especially Order 636 that unbundled wholesale gas services, local distribution companies have unbundled services to the larger retail customers. NIPSCO has had the highest percentage of unbundled service over the past ten years, averaging 54 percent. It is followed by SIGECO, Indiana Gas and Citizens, with 41, 23 and 17 percent, respectively. The use of unbundled services by industrial gas customers has been more extensive than that of commercial customers. There has been no residential gas transportation in Indiana to date.

Utility Activities

In 1995 the Indiana General Assembly passed Senate Enrolled Act 637, legislation designed to allow more flexible regulation of energy utilities. The Act, codified as IC 8-1-2.5, requires the Commission to consider any petition filed by a utility proposing alternative regulation. The Commission must determine whether the proposal would be beneficial to the utility, its customers and the state, and if it will promote efficiency and competition.

In response to Act 637, Indiana Statewide Association of Rural Electric Cooperatives, on behalf of 32 Rural Electric Membership Cooperatives (REMCs), filed a petition with the IURC on June 10, 1996, seeking approval of an alternative regulatory plan (ARP). The proposed ARP was the first by an electric utility.

On August 8, 1996, the Office of the Utility Consumer Counselor (OUCC) filed a Motion to Dismiss along with a Memorandum In Support of the Motion to Dismiss. This Motion was joined by Citizens Action Coalition (CAC), Central Soya and GM. On September 5, 1996, the IURC denied the Motion to Dismiss. The CAC and OUCC initiated an interlocutory appeal, so the proceedings are stayed until the Court of Appeals issues a ruling on the Motion to Dismiss.

On July 21, 1997, Indiana Statewide filed a new petition seeking IURC approval of an amended ARP.

On August 21, 1997, Indianapolis Power & Light Company (IPL) filed an alternative regulatory plan with the Indiana Utility Regulatory Commission. The plan would allow residential and small commercial customers with loads of less than 2,000 kW of demand the option of choosing one of three alternative pricing options: Fixed Bill, Fixed Rate and Green Power. IPL will limit the availability of these three options to 3 ½ years, after which the options will be discontinued.

NIPSCO was the first natural gas utility in the state of Indiana to propose an ARP, in order to adapt more readily to market changes in the evolving gas industry. NIPSCO sought to interject competitive forces into its business practices and provide unbundled gas distribution services to all classes of customers. The net effects of the proposed changes, which will be phased in over time, will be more service options for all of NIPSCO's customers with no loss of current service options. On October 8, 1997, the commission approved the agreement. Resolution of this matter is a major step forward in the flexible regulation of NIPSCO and other natural gas utilities in Indiana that look to this case for guidance in planning their future.

American Electric Power and Cinergy have been very active in investing in foreign utility companies (FUCOs). A FUCO is any company that owns or operates facilities not located in the United States for generating, transmitting or distributing electricity for sale, and derives none of its income from utility operations conducted in the United States. In March 1997, NIPSCO Industries, Inc. (NIPSCO) acquired IWC Resources Corporation (IWCR) for approximately $290 million. This affiliation allows NIPSCO entry into the water utility business through IWCR's primary subsidiary, Indianapolis Water Company.

On September 12, 1997, the IURC denied a complaint filed against Citizens Gas and Coke Utility and Indiana Gas Co. by a group of their large industrial customers over the utilities' joint venture that formed ProLiance, an Indianapolis-based marketer of energy and related services that was formed in March 1996 by affiliates of Indiana Energy and Citizens Gas. In its order, the Commission ruled that the agreements by which the utilities created ProLiance are in the public interest, in part, because efficiencies gained by consolidating the gas supplies of the two utilities have caused gas rates to decrease for each utility. The Commission advised the utilities, however,

that it would be taking some of the concerns raised in the complaint into account when scrutinizing future gas cost adjustment filings. Also in its order, the IURC admonished Indiana Gas and Citizens Gas, saying that although the Commission would not disapprove the formation of the marketing company, it would have preferred the utilities to seek Commission approval of the new arrangement through an alternative regulatory plan.

Restructuring at State and Federal Levels

Electric utility restructuring has been an active issue in most states since the last Energy Report to the Regulatory Flexibility Committee of the Indiana General Assembly. Thirteen state legislatures considered some sort of restructuring-related legislation. Many of these bills were abandoned before a vote was taken, while others were voted down. State regulatory commissions are also busy addressing restructuring issues, although they are in very different stages in the process.

Many state legislative bodies and commissions are still in the "educational" phase of addressing electric utility restructuring. Task forces and study groups have been established by either the state commission or legislative body in eleven states. Several states have separate groups established by both the state commission and the state legislative body. The groups range from informal monitoring bodies to formally established groups with responsibilities to propose legislation or procedures for initiating retail competition. In 1995-96, the IURC conducted educational forums regarding restructuring the electric utility industry.

As of summer 1997, five states had established retail competition electricity pilot programs: Illinois, New Hampshire, Massachusetts, New York and Washington. These programs have provided valuable information for not only the states involved, but those considering retail competition. Consumers, utilities and marketers have experienced first-hand the advantages and disadvantages of competition.

Despite the FERC's effort to encourage competition in the wholesale gas markets since the mid-1980s, there has been very little movement by states to promote retail gas competition. As a result, most states currently only allow large customers (e.g., industrial or electric utilities) to purchase "unbundled" gas services. In the last two years, 12 states have asked LDCs to propose plans to offer unbundled service to smaller customers, at least on an experimental basis. The legislature and/or the state commissions in ten other states have expressed their intention to allow all customers to have their choice of gas suppliers by 2000.

In the past two years, there has been an increased interest in electricity restructuring at the federal level. While no restructuring bill is expected to pass Congress this session, enough bills

have been introduced in both the House and the Senate in 1996 and 1997 to place the issue in a key position for the coming session.

In the electric industry restructuring debate, one message continually arises: no matter what, reliability must be maintained. Partly in response to two massive power outages that cascaded through the western power grid in the summer of 1996, the Department of Energy (DOE) formed the Electric System Reliability Task Force. Its mission is to explore how reliability can be maintained and even improved in the transition to and the final structure of a competitive industry. The Task Force, chaired by former Congressman Philip Sharp, is expected to issue an interim report sometime in the fall of 1997.

Last year, the North American Electric Reliability Council (NERC) formed its own "reliability compliance team," which issued a report in October 1996. The report concluded that instead of voluntary reliability standards, NERC should develop mandatory, contract-based reliability protocols that include sanctions and business incentives to enforce compliance.

III. INDIANA'S ENERGY MARKETS

A. Review of the Electricity Industry

1. Industry Structure

Electric utilities in the United States are categorized by their type of ownership: government (federal and municipal), cooperative and investor-owned. The utilities have the same goal, to provide reliable electric service at reasonable cost to their customers, but distinct corporate structures result in different methods employed by the utilities to meet this goal. Because of the differences in utility structure, government policy does not affect each type of utility in the same manner.

a. Investor-Owned Utilities

The type of utility that is most significant in terms of generation and customers served is the investor-owned (IOU). Five major investor-owned utilities operate within the state: Indianapolis Power & Light (IPL), Indiana Michigan Power (I&M), Northern Indiana Public Service (NIPSCO), PSI Energy (PSI) and Southern Indiana Gas & Electric (SIGECO). IOUs are for-profit enterprises funded by debt and equity. IOUs are judged by the same standards as any publicly held company; investor services rate their bond issues and make recommendations on stock purchases. Most IOUs are vertically integrated, meaning they own facilities for generation, transmission and distribution (T&D). The significant level of investment needed to construct and maintain the systems results in high leverage for many IOUs.

All of Indiana's IOUs are owned by holding companies. Holding companies are entities that own enough stock in another company to influence management of the held company. Holding companies are popular in the electricity industry because its capital-intensive nature makes it economical to combine functions. Two of the state's IOUs, PSI and Indiana Michigan Power, are subsidiaries of multi-state holding companies (Cinergy and American Electric Power, respectively). Multi-state holding companies are required under the Public Utility Holding Company Act (PUHCA) to register with the Securities and Exchange Commission (SEC), and the SEC monitors their actions to ensure compliance with PUHCA regulations.

Table 1 presents generation and sales information for Indiana's five major IOUs. The "Sales for Resale" illustrates that IOUs are typically able to generate enough power for their own requirements and produce power for sale in the wholesale market.

Table 1
Investor-Owned Utility Statistics -- 1996 [2]

UTILITY	CAPACITY (MW)	TOTAL SALES (GWh)	SALES FOR RESALE (GWh)	RESIDENTIAL SALES (GWh)	COMMERCIAL SALES (GWh)	INDUSTRIAL SALES (GWh)
I&M	4,435	35,585	18,740	5,140	4,328	7,295
IPL	2,986	13,326	754	4,367	2,118	6,772
PSI	5,781	33,490	10,444	7,093	5,881	10,008
NIPSCO	3,392	16,741	1,678	2,700	2,887	9,318
SIGECO	1,238	6,084	1,213	1,318	1,174	2,074

SOURCE: 1996 Annual Reports and FERC Form 1

b. Municipal Utilities

There are 78 municipally owned electric utilities in Indiana, 34 of which are regulated by the Indiana Utility Regulatory Commission (IURC or the Commission). Municipals are organized as nonprofit local government agencies and pay no property taxes or dividends, although net revenue can be turned over to the general city fund if the city elects to do so. Municipals raise capital through the issuance of tax-free bonds.

Municipal utilities typically own very little, if any, generating capacity; they purchase electricity from other sources and resell it to their retail customers. The reseller status limits a municipal's need to raise large amounts of capital because it does not invest in capital-intensive generation. The advantages of a municipal include the local government receiving revenue from

[2] 1,000 Watts = 1 KW; 1,000 KW = 1 MW; 1,000 MW = 1 GW; 1 GWh = 1 GW of generaton for one hour.

earnings, and generally lower electricity rates for the municipality due to the low capital investment and tax-exempt status.

Many municipals in the state are members of the Indiana Municipal Power Agency (IMPA). IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power. IMPA is a political subdivision of the state under Indiana Code 8-1-2.2 and is not subject to state or federal income taxes.

IMPA owns generating facilities and has member-dedicated generation. It also holds ownership interest in two units, Gibson 5 (co-owned with PSI and Wabash Valley Power Association) and Trimble County 1 (co-owned with Louisville Gas and Electric and the Illinois Municipal Electric Agency). It meets the rest of its members' needs through purchased power.

c. Cooperatives

Another type of nonprofit electric utility is the cooperative. Forty-three distribution cooperatives exist in Indiana, of which 14 have opted out of Commission jurisdiction. Cooperatives were originally formed to bring electric service to rural areas. They are similar to municipals in that they generally purchase electricity from private suppliers at wholesale rates rather than own generation facilities.

Although cooperatives were created to distribute power, since the 1960s over 50 generating and transmission cooperatives (G&T cooperatives) have been formed nationally to supply power to distribution cooperatives. Within Indiana, there are two G&T cooperatives: Hoosier Energy and Wabash Valley Power Association. These G&T cooperatives serve as coordinators of bulk power supplies and transmission services for their members, as IMPA does for municipals.

Table 2 illustrates the proportion of power purchases to generation for IMPA and the G&T cooperatives, Hoosier Energy and Wabash Valley Power Association. The table illustrates that Hoosier Energy owns a significant amount of generating capacity compared to Wabash Valley.

Table 2
IMPA/G&T Cooperatives Statistics -- 1996

UTILITY	CAPACITY (MW)	GENERATION (GWh)	PURCHASES (GWh)	SALES (GWh)
IMPA	555	1,360	2,583	4,165
Hoosier Energy	1,266	8,266	503	8,072
Wabash Valley	156	941	3,719	4,442

SOURCE: 1996 Annual Reports to the IURC

2. Indiana Electricity Prices

Table 3 presents a comparison of average electric utility revenue per kilowatt hour (kWh) by state for 1995. It is important to note Indiana's ranking as the eighth lowest, indicating Indiana is a "low-cost state." The cheaper western states have the advantage of hydropower and abundant coal reserves, while Tennessee has the TVA to provide low-cost power. Kentucky has access to both plentiful coal supplies and TVA power. Indiana's favorable ranking comes from not only its coal reserves, but from depreciated plants and relatively little utility investment in expensive nuclear power.

For more detailed sales, revenue and market share information for Indiana utilities in 1996, please see Appendix 1.

Table 3: Average Revenue, Cents Per kWh by Sector and State -- 1995

State	Residential	Commercial	Industrial	Other	All Sectors (rank: highest to lowest)
New Hampshire	13.50	11.38	9.56	12.32	11.72
Hawaii	13.32	12.16	9.27	12.11	11.29
New York	13.90	11.92	5.79	9.07	11.06
Connecticut	11.95	10.33	7.94	14.38	10.50
New Jersey	11.98	10.23	8.15	18.07	10.44
Rhode Island	11.47	10.08	8.87	11.44	10.38
Alaska	11.24	9.54	8.38	13.26	10.17
Massachusetts	11.26	9.93	8.41	14.31	10.12
California	11.61	10.49	7.37	6.73	9.91
Maine	12.51	10.28	6.65	15.67	9.49
Vermont	10.52	9.80	7.56	14.03	9.46
Pennsylvania	9.72	8.33	5.92	11.29	7.93
Illinois	10.37	7.88	5.27	6.80	7.69
Arizona	9.09	8.06	5.26	5.15	7.62
District of Columbia	7.62	7.15	4.36	6.33	7.12
Maryland	8.43	6.91	4.23	8.79	7.06
Michigan	8.34	7.86	5.13	10.71	7.05
Florida	7.82	6.39	5.16	6.69	7.01
Delaware	9.09	7.08	4.72	11.95	6.91
US Average	**8.40**	**7.69**	**4.66**	**6.88**	**6.89**
New Mexico	8.93	7.91	4.40	5.95	6.77
Georgia	7.85	7.32	4.52	8.60	6.62
North Carolina	8.12	6.47	4.85	7.21	6.58
Kansas	7.92	6.68	4.82	9.21	6.56
Arkansas	7.98	6.83	4.51	6.65	6.27
Virginia	7.84	6.07	4.16	5.21	6.26
Missouri	7.25	6.18	4.53	7.05	6.25
Ohio	8.60	7.68	4.17	6.26	6.24
South Dakota	7.08	6.55	4.43	4.58	6.20
Colorado	7.42	6.07	4.52	7.87	6.12
Texas	7.71	6.64	3.98	6.44	6.10
Nevada	7.11	6.75	5.05	5.00	6.10
Iowa	8.24	6.44	3.94	6.13	6.03
Mississippi	6.99	7.01	4.44	8.56	5.98
Louisiana	7.23	6.77	3.97	6.97	5.75
North Dakota	6.23	6.20	4.50	4.21	5.71
South Carolina	7.53	6.35	4.00	5.87	5.69
Minnesota	7.17	6.19	4.30	7.21	5.58
Oklahoma	6.82	5.78	3.75	4.93	5.57
Alabama	6.71	6.73	4.05	7.35	5.47
Nebraska	6.37	5.56	3.84	5.86	5.40
Wisconsin	6.97	5.78	3.78	6.85	5.36
West Virginia	6.50	5.86	4.03	9.36	5.34
Utah	6.94	5.92	3.72	4.46	5.30
Indiana	**6.74**	**5.92**	**3.94**	**9.12**	**5.24**
Tennessee	5.91	6.65	4.50	7.56	5.21
Oregon	5.49	5.06	3.47	5.49	4.67
Montana	6.09	5.31	3.44	6.21	4.65
Wyoming	6.09	5.11	3.50	7.16	4.32
Washington	4.97	4.82	2.96	3.75	4.10
Idaho	5.33	4.48	2.81	5.13	4.09
Kentucky	5.62	5.25	2.93	4.68	4.07

SOURCE: U.S. Department of Energy, Energy Information Administration, Electric Sales and Revenue 1995, December 1996, p. 25

B. Recent Developments in Electricity

1. Alternative Regulatory Plans

In 1995 the Indiana General Assembly passed Senate Enrolled Act 637, legislation designed to allow more flexible regulation of energy utilities. The Act, codified as IC 8-1-2.5, requires the Commission to consider any petition filed by a utility proposing alternative regulation. The Commission must determine whether the proposal would be beneficial to the utility, its customers and the state, and if it will promote efficiency and competition.

a. Indiana Statewide

Indiana Statewide Association of Rural Electric Cooperatives, on behalf of 32 Rural Electric Membership Cooperatives (REMCs), filed a petition with the IURC on June 10, 1996, seeking approval of an alternative regulatory plan (ARP). The proposed ARP was the first by an electric utility under IC 8-1-2.5.

Indiana Statewide petitioned the IURC to decline to exercise its jurisdiction over the petitioning REMCs on most issues, although the cooperatives would not formally opt out of IURC jurisdiction. Specifics of the plan included:

1. The ARP would give deference to the REMC's management with respect to personnel, operating and management practices affecting rates and charges.
2. The REMC's rates would be independent of the rates of its wholesale supplier.
3. Reductions in revenues applied to all rate classes using an existing rate design based on a cost-of-service study performed consistent with generally accepted practices and filed with the IURC would be presumed reasonable, and may be placed in effect upon thirty days' notice to members.
4. Reductions involving new rate design based on cost-of-service established by a current cost-of-service study filed with the IURC may be implemented thirty days after notice of the proposed rate changes to customers and shall become permanent within sixty days of such notice unless a petition for a hearing is requested within thirty days' of notice by the Office of the Utility Consumer Counselor (OUCC) or one percent of the REMC's members. The rates proposed by the REMC would be presumed reasonable and the person(s) filing the request for hearing would have the burden of proving otherwise.
5. Increases in recurring rates would be conclusively presumed reasonable and may be placed into effect upon thirty days' notice to members if the new rates do not produce additional annual revenues of more than three percent and the rate design is consistent with a cost-of-service study on file with the IURC.

6. Other rate increases would be placed into effect upon thirty days' notice to members and would become permanent sixty days thereafter unless a request for rehearing is received from the OUCC or one percent of the REMC's members within twenty days. The proposed rates once placed into effect would not be subject to refund.
7. The ARP provides for customer-specific contracts for new load or to retain existing load in excess of one megawatt, at the sole discretion of the REMC's board and without the necessity of IURC approval. The ARP would also require the IURC to keep on file the contract, but it would be on a confidential basis.

On August 8, 1996, the OUCC filed a Motion to Dismiss along with a Memorandum In Support of the Motion to Dismiss. This Motion was joined by Citizens Action Coalition (CAC), Central Soya and GM. On September 5, 1996, the IURC denied the Motion to Dismiss. The CAC and OUCC initiated an interlocutory appeal, so the proceedings are stayed until the Court of Appeals issues a ruling on the Motion to Dismiss.

On July 21, 1997, Indiana Statewide filed a new petition, "1997 PETITION," under a new cause number seeking IURC approval of an ARP which is somewhat different than the ARP previously discussed. GM has filed a Motion to Dismiss with the Commission which is pending.

The first two components of the new plan are exactly the same as the old plan. However, under the new plan, in the area of rate changes, the REMC is required to file and keep current a cost-of-service study upon which to base rate changes. The mechanisms of the various types of rate changes remain essentially the same as described for the old plan, but considerably more procedural detail has been added. In regard to customer-specific contracts, the new plan remains much the same as the old, except that guidelines are established to process the contracts and supporting documentation must be filed. Other changes to the plan include changing the definition of "burden of proof" and clarifying the role of the Office of the Utility Consumer Counselor in processing the rate change filings.

b. Indianapolis Power & Light

On August 21, 1997, Indianapolis Power & Light Company filed an alternative regulatory plan with the Indiana Utility Regulatory Commission. The plan would allow residential and small commercial customers with loads of less than 2,000 kW of demand the option of choosing one of three alternative pricing options: Fixed Bill, Fixed Rate and Green Power.

Under the Fixed Bill Option, available only to residential customers who have been at the same location for at least one year, the customer will pay the same charge each month for a year, regardless of how much electricity is used. There will be no bill reconciliation at the end of the

year. The monthly charge will be based on the customer's electricity usage for the previous 12 months and the base rates, including fuel costs and the recovery of lost revenues from demand-side management programs, applicable to the customer at the time of application. At the end of one year the customer may reapply for the Fixed Bill Option. The monthly charge would then be updated to reflect most recent usage levels and rates.

Under the Fixed Rate Option, the customer can choose to pay the same fixed rate for electricity for a period from one to three years. During the length of the contract, the fixed rate will not be affected by any changes in IPL's basic rates and charges.

The "Green Power" Option will allow customers to choose renewable resource power to displace some or all of their usual source of electricity. The portion of the customer's electricity supply being provided through renewable resources will be sold at a premium over IPL's usual rates and charges.

IPL plans to offer incentives to encourage participation in these options. The incentives could include credits to the customer's bill, energy-saving products or services or contributions to the customer's preferred charity. IPL will limit the availability of these three options to 3 ½ years, after which the options will be discontinued. The ARP is pending before the Commission.

2. Diversification Activities

Utility diversification efforts during the 1980s generally involved non-core businesses like real estate and financial services. The track record of this form of public utility diversification is mixed. Most of the more recent initiatives seem to be focused on convergence and activities more closely related to the core activities of utility companies. Some examples of convergence include combining an electric utility with an adjacent or overlapping gas distributor; interstate pipeline company; power marketer; or non-energy service provider such as a communications or electronic security firm. There are two converged electric and gas utilities in Indiana, NIPSCO and SIGECO. Another example would be the significant investments by utility holding companies in "exempt wholesale generators" (EWGs) and "foreign utility companies" (FUCOs). EWGs are defined as any persons engaged in owning or operating eligible facilities and selling energy exclusively at wholesale. A FUCO is any company that owns or operates facilities not located in the United States for generating, transmitting or distributing electricity for sale, and derives none of its income from utility operations conducted in the United States.

a. Cinergy and AEP Foreign Investments

American Electric Power and Cinergy, Indiana's only registered utility holding companies, have been very active in investing in FUCOs. On February 24, 1997, AEP and Public Service

Company of Colorado announced their intention to acquire Yorkshire Electricity Group for an aggregate purchase price of approximately $2.4 billion. Yorkshire is primarily a distribution company, serving approximately 2.1 million customers in England. On September 22, 1996, a subsidiary of AEP signed a joint venture agreement with two local Chinese partners to form the Nanyang General Light Electric Company in the People's Republic of China.

Cinergy indirectly owns a one percent interest in Edesur, S.A., a FUCO that owns an electricity distribution network serving approximately 2.1 million customers in the southern half of the city of Buenos Aires, Argentina. Cinergy also indirectly owns 50 percent of Midlands, a FUCO serving approximately 2.2 million customers in mid-central England. Cinergy acquired its interest in Midlands in a 50-50 joint venture transaction with GPU, Inc.

The SEC has a "safe harbor" that permits a registered holding company to invest up to 50 percent of the holding company's consolidated retained earnings without having to seek SEC preapproval so long as the three following criteria are satisfied:

1. There has been no bankruptcy of an associate company.
2. The holding company's consolidated retained earnings have increased.
3. The holding company has never reported a full year "operating loss" due to investments in exempt projects.

Both AEP and Cinergy are seeking SEC authority to invest up to 100 percent of the holding company's consolidated retained earnings in EWGs and FUCOs without having to seek SEC preapproval for each specific investment.

Under the Energy Policy Act of 1992, state commissions are in an advisory role with respect to investments in FUCOs by registered holding companies. IURC review of the AEP and Cinergy proposals concentrated on the potential impact any increased investment in EWGs and FUCOs might have on the holding companies and the utility company subsidiaries. There are no sure ways to completely insulate the holding company or the utility subsidiaries from the potential risks and benefits associated with such investments. The risks, however, can be minimized in a number of different ways. The formation of a separate subsidiary and substantial use of non-recourse financing are two structural safeguards. Both of these safeguards have been used by AEP and Cinergy for investments in FUCOs. The only other real safeguard is requiring access by state commissions to the information necessary to monitor the performance of the subsidiaries and instituting accounting and separation rules. These requirements are satisfied through SEC regulations.

The IURC submitted letters to the SEC stating that it has no objection to an increase in the authority of AEP or Cinergy to invest in EWGs and FUCOs. The IURC certified that it has the

authority and jurisdiction to protect utility subsidiary ratepayers, and intends to exercise such authority.

Approval of the proposals by the SEC is pending.

b. NIPSCO/IWC Merger

In March 1997, NIPSCO Industries, Inc. (NIPSCO) acquired IWC Resources Corporation (IWCR) for approximately $290 million. Although IWCR became a wholly owned subsidiary of NIPSCO, IWCR continues to operate with local management, employees and directors. This affiliation allows NIPSCO entry into the water utility business through IWCR's primary subsidiary, Indianapolis Water Company. Indianapolis Water provides water service to approximately 235,000 customers in Indianapolis and adjacent counties with potential to expand its service area. NIPSCO also acquired IWCR's non-regulated utility service-related businesses, including SM&P Utility Resources Inc., a major utility locating and marking service of underground facilities, and Miller Pipeline Corporation, a major pipeline construction business.

C. Review of the Natural Gas Industry

1. Industry Structure

Gas utilities in the United States are categorized into municipally owned and investor-owned. Despite their different forms of ownership and corporate structures, municipal and investor-owned utilities share the goal of providing reliable gas service at reasonable cost. Because of the differences in governance and corporate structure, government policy does not affect each type of utility in the same manner.

a. Investor-Owned Utilities

Investor-owned utilities are the largest sellers of natural gas to retail customers in the United States. In Indiana, there are three large investor-owned gas utilities, Indiana Gas, NIPSCO and SIGECO, and 17 smaller IOUs. The three largest IOUs are owned by holding companies, and two of them, NIPSCO and SIGECO, also operate major electric utilities. Gas IOUs, unlike their electric IOU counterparts, are not vertically integrated; they typically do not own gas production or pipeline facilities beyond their local distribution area.

b. Municipally Owned Utilities

There are 19 municipally owned gas utilities in Indiana, four of which are regulated by the IURC. The largest municipal gas utility in the state is Indianapolis-based Citizens Gas and Coke,

which is regulated by the IURC. Municipals are organized as nonprofit local government agencies and pay no property taxes or dividends, although net revenue can be turned over to the general city fund (in lieu of taxes) if the city elects to do so. Municipal utilities raise capital through the issuance of tax-free bonds.

Like their IOU counterparts, municipal gas utilities serve as a "reseller" to their retail customers. Typically, municipal gas utilities purchase gas supply and transportation rights rather than having any ownership in production or interstate pipeline facilities.

c. Indiana Sales and Transportation of Gas

Movement toward deregulation of the gas industry has been synonymous with further unbundling of gas services by different providers, whether they have been interstate pipelines or local gas distribution companies. For the past several years, LDCs have been both a merchant, providing bundled sales and transportation service to many of their customers, including residentials; as well as a transporter, moving gas through its system for industrial and commercial customers that have purchased gas directly from producers or marketers. These transportation-only customers pay just a transportation fee to the LDC.

Because the degree of unbundling can be a rough measure of deregulation, the following tables and graphs compare historically the degree of unbundling in Indiana by its four largest LDCs. Sales figures are based on sales of gas made by LDCs to customers that purchase bundled service, which includes both the gas and transportation service. Transportation figures include only volumes of gas owned by end users that move through an LDC's system. Throughput figures include all volumes of gas moving through the LDC's system regardless of ownership. Degrees of unbundling increase as transportation volumes increase relative to the total throughput during a given period.

Table 4 presents sales and Table 5 presents transportation information for Citizens Gas, Indiana Gas Company, NIPSCO and SIGECO. For more detailed information, see Appendix 2.

Table 4
Sales (Dth) for the Four Largest Gas Utilities in Indiana -- 1996

Utility	Residential	Commercial	Industrial	Other	Total
Citizens Gas	28,483,330	17,041,493	8,313,991	3,029,750	56,868,564
Indiana Gas	50,507,000	20,178,000	21,892,000		92,577,000
NIPSCO	77,050,000	29,401,000	16,528,000	7,922,000	130,901,000
SIGECO	10,435,599	5,174,821	2,667,594	985,306	19,263,320

SOURCE: IURC data requests.

Table 5
Transportation of Gas (Dth) by the Four Largest Gas Utilities in Indiana – 1996

Utility	Commercial	Industrial	Other	Total
Citizens Gas	929,276	5,084,490	163,656	6,177,422
Indiana Gas		34,165,000		34,165,000
NIPSCO	3,740,000	151,446,000		155,186,000
SIGECO	268,144	11,049,737	483,495	11,801,376

SOURCE: IURC data requests.

2. Indiana Gas Prices

Table 6 provides a comparison of average natural gas price by sector and state for 1997 and 1996. The price to Indiana residential and commercial customers is below the national average for both years.

Table 6: Average Price* of Natural Gas by Sector and State -- 1997 and 1996

State	Citygate Price		Residential		Commercial		Industrial		Electric Utilities	
	1997	1996	1997	1996	1997	1996	1997	1996	1997	1996
Alabama	3.82	3.24	8.07	6.54	7.02	5.90	3.56	3.78	2.95	3.20
Alaska	1.15	1.58	3.71	3.51	2.48	2.33	1.53	1.51	1.63	1.27
Arizona	3.16	2.16	7.06	7.02	5.11	4.93	4.05	3.91	4.10	2.60
Arkansas	3.24	2.53	6.33	5.40	5.12	4.40	3.63	3.00	2.72	2.91
California	2.97	2.26	6.30	6.32	6.58	6.35	4.12	3.70	3.45	2.77
Colorado	na	2.17	na	4.11	na	3.64	na	1.77	3.00	1.87
Connecticut	5.39	5.19	10.37	9.90	7.82	7.72	5.13	5.23	2.67	2.79
Delaware	4.30	3.46	7.85	6.48	6.49	5.45	4.49	4.05	3.16	4.08
Florida	4.06	3.74	11.44	10.38	6.75	6.49	4.50	4.34	2.45	3.35
Georgia	3.99	3.60	7.36	6.37	6.55	5.59	5.34	4.43	3.00	5.26
Hawaii	6.80	5.72	na	19.18	na	13.69	---	---	---	---
Idaho	2.19	2.09	4.92	5.08	4.39	4.50	2.75	3.18	---	---
Illinois	3.17	3.17	5.85	4.85	5.42	4.55	5.02	3.97	2.36	3.11
Indiana	**3.05**	**3.13**	**6.23**	**5.05**	**5.46**	**4.32**	**4.33**	**3.21**	**3.48**	**3.65**
Iowa	3.51	3.11	5.68	5.00	4.93	4.07	3.97	3.29	3.48	4.16
Kansas	1.80	2.89	6.32	5.32	5.80	4.99	2.97	2.50	2.71	2.33
Kentucky	3.72	3.17	6.18	5.03	5.71	4.61	4.34	3.77	3.69	3.70
Louisiana	3.10	3.23	6.87	6.06	6.28	5.83	na	2.89	2.83	3.50
Maine	4.22	4.32	8.49	7.71	7.89	6.99	6.09	5.96	---	---
Maryland	na	na	na	6.88	na	5.80	na	5.21	3.54	5.15
Massachusetts	na	3.53	na	8.76	na	7.06	na	6.17	2.97	4.23
Michigan	3.05	2.95	4.96	4.56	4.81	4.48	4.13	4.01	0.62	0.76
Minnesota	3.37	2.81	5.62	5.05	4.90	4.40	3.30	2.88	2.32	2.37
Mississippi	na	3.27	na	5.21	na	5.47	na	3.42	2.81	4.37
Missouri	3.56	2.76	6.19	5.44	5.82	5.13	4.78	4.55	3.50	2.87
Montana	na	2.83	na	4.68	na	4.62	na	4.79	4.89	8.78
Nebraska	3.47	2.72	4.93	4.56	na	4.45	3.75	3.13	2.37	2.10
Nevada	3.39	2.72	5.90	6.48	4.99	4.86	6.17	4.94	2.09	2.10
New Hampshire	4.18	4.07	6.88	6.94	7.99	6.60	4.91	4.83	---	---
New Jersey	4.01	3.73	7.14	6.93	6.59	7.57	4.13	4.17	3.06	2.99
New Mexico	2.59	1.46	5.63	4.24	4.50	3.24	4.17	2.96	2.66	2.16
New York	na	3.27	na	8.03	na	na	na	5.21	2.98	3.79
North Carolina	4.01	3.68	8.88	6.93	7.33	5.92	5.11	4.38	2.84	3.08
North Dakota	3.32	2.72	4.37	4.31	4.00	3.85	3.04	3.31	3.31	3.58
Ohio	5.37	4.02	6.68	5.30	6.35	4.97	5.76	4.57	4.01	3.76
Oklahoma	3.15	2.55	6.07	5.03	5.66	4.49	4.23	2.86	3.42	3.42
Oregon	2.41	2.22	5.87	6.06	4.57	4.87	3.21	3.21	1.73	na
Pennsylvania	4.00	3.59	8.07	6.84	7.41	6.14	4.97	4.28	3.10	3.92
Rhode Island	4.08	3.93	9.27	7.80	8.41	6.92	4.56	4.76	3.25	2.39
South Carolina	3.68	3.95	8.69	7.28	7.14	6.32	3.75	3.90	4.10	4.48
South Dakota	na	2.80	na	4.71	na	3.88	na	1.97	---	---
Tennessee	na	3.44	na	6.05	na	5.66	na	3.80	---	---
Texas	3.74	3.17	6.05	5.43	na	4.35	2.76	2.48	2.75	2.47
Utah	2.56	2.17	4.88	4.34	3.65	3.30	2.40	2.05	---	20.25
Vermont	2.09	2.88	6.13	6.12	5.23	5.24	3.12	3.61	3.15	2.81
Virginia	4.19	3.61	8.40	7.15	6.53	5.53	4.13	4.45	2.74	2.36
Washington	na	2.09	na	5.47	na	4.75	na	2.50	6.99	5.17
West Virginia	3.16	3.37	6.80	6.90	6.24	6.21	2.98	2.80	5.00	3.74
Wisconsin	3.54	2.99	na	5.82	na	4.71	4.04	3.74	3.06	3.18
Wyoming	na	na	na	4.16	na	3.73	na	3.01	15.06	18.37
Average	**3.50**	**3.16**	**6.65**	**5.90**	**5.81**	**5.29**	**3.68**	**3.40**	**2.81**	**2.83**

--- = Not Applicable na = Not Available

* (Dollars per Thousand Cubic Feet, the information is preliminary based on year-to-date information)

SOURCE: US Department of Energy, Energy Information Administration, Natural Gas Monthly, August 1997 pages 49, 52, 55, 58 and 61.

a. Unbundling

Table 7 summarizes natural gas throughput data for Citizens Gas, Indiana Gas Company, NIPSCO and SIGECO. These four companies collectively represent about 90 percent of the natural gas retail deliveries in the state. This schedule reflects the percentage of total gas transported to the total gas throughput for each of the four utilities and for the four utilities combined.

These percentages indicate the extent to which natural gas services were unbundled in Indiana for each of the last 10 years. NIPSCO has had the highest percentage of unbundled service with a 54 percent average over the last 10 years, followed by SIGECO, Indiana Gas and Citizens with 41, 23 and 17 percent.

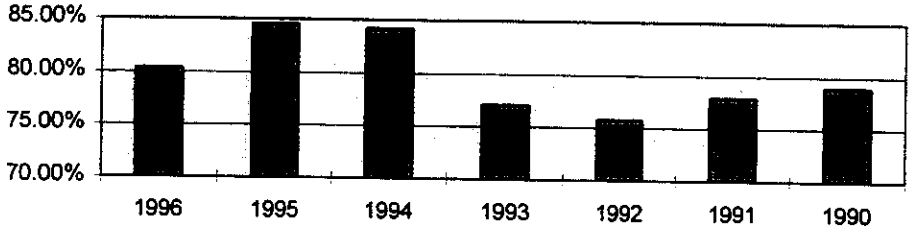
Table 7
Percentage of Gas Transported to Total Gas Throughput

% Total Transportation to Total Throughput	1996	1995	1994	1993	1992	1991	1990	1989	1988	1987	10 yr. Average
Citizens Gas & Coke Utility	9.8	19.7	23.2	17.4	11.8	21.6	16.6	16.9	18.7	19.3	17.5
Indiana Gas Company, Inc.	27.0	30.4	25.9	11.1	13.2	18.8	23.3	27.0	26.7	28.4	23.2
NIPSCO	54.2	58.6	60.2	59.2	57.4	55.8	55.5	50.4	49.2	41.2	54.2
SIGECO	38.0	43.7	42.9	40.3	37.3	38.5	41.7	41.5	40.0	45.9	41.0
Combined Weighted Average	40.9	45.8	46.4	41.8	40.7	42.1	43.0	40.9	40.5	36.1	41.8

SOURCE: IURC data requests.

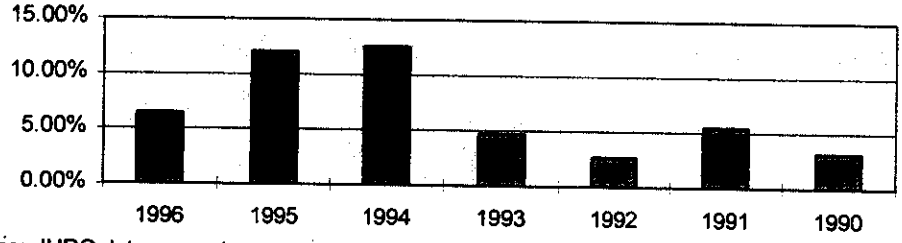
Graphs 1 and 2 depict total gas transportation, relative to total gas throughput, for the commercial and industrial sectors for the four utilities studied. These graphs show that use of unbundled services by industrial gas customers has been more extensive than that by commercial customers. As shown previously in Table 5, Indiana Gas Company has not provided transportation-only service to commercial customers. Despite the drop in gas transportation from 1995 to 1996, there does not appear to be any discernable trend. There has been no residential gas transportation in Indiana to date.

Graph 1: Percent of Industrial Throughput That is Transportation-Only Service



Source: IURC data requests.

Graph 2: Percent of Commercial Throughput That is Transportation-Only Service



Source: IURC data requests.

D. Recent Developments in Natural Gas

1. Alternative Regulatory Plans

a. NIPSCO

NIPSCO was the first natural gas utility in the state of Indiana to make use of Senate Enrolled Act 637, which was signed into law on April 17, 1995. This Act, I.C. 8-1-2.5, allows energy utilities to propose ARPs to cost-based regulation, so that they can adapt more readily to market changes in their evolving industries. Through the provisions of this Act, NIPSCO filed Docket Number 40342 on November 29, 1995, and sought to interject competitive forces into its business practices and provide unbundled gas distribution services to all classes of customers. The net effects of the proposed changes, which will be phased in over time, will be more service options for all of NIPSCO's customers with no loss of current service options.

On October 8, 1997, the commission approved the agreement and in its order stated:

> There is no dispute that the public utility industry is moving toward competition. The challenge of transitioning from a monopolistic market to

one of competition is enormous. The Indiana General Assembly has provided the Commission with a valuable tool by enacting I.C. 8-1-2.5 et seq. We believe the Legislature intended that the Commission should be given the flexibility to approve opportunities to remove regulatory burdens impeding the efficient entry of competition while giving due regard to the interests of consumers and the public.

In its original filing, NIPSCO requested that it be allowed to engage in negotiations with all interested parties in an attempt to settle any of the issues raised by its proposal. The IURC allowed the private negotiations; however, the utility ultimately produced a settlement with less than all the interested parties becoming signatories.

The settlement agreement filed by NIPSCO on May 9, 1997, addressed the following key issues:

1. New Services Tariffs. To effectuate the ARP, NIPSCO has proposed an array of new service offerings.
2. System-Wide Unbundling (Residential Pilot Program). NIPSCO will implement a system-wide unbundling program for the purpose of providing customer choice of gas suppliers. The program will be implemented upon approval by the IURC and be effectuated no later than December 31, 2004. Initially, a pilot program for residential customers will be limited, but later will be enlarged as determined by the participants to this proceeding. The purpose of the pilot program is to determine (1) the operational and administrative issues that will be raised in the process of unbundling NIPSCO's system; (2) the customers' response to customer choice; (3) the issues, if any, involving market segmentation; (4) the ability to provide safe, reliable and efficient services in an unbundled environment, and (5) the existence of barriers to entry and exit from an unbundled market. A key element to success of unbundling at the residential level is the mechanism for third-party suppliers to aggregate multiple small customer loads. During the transition period, NIPSCO agrees to proceed in incremental steps so as to minimize any transition costs. Also, NIPSCO agrees to give annual informational presentations to all interested parties on the progress of unbundling.
3. Maintain Merchant Function During Transition Period. NIPSCO maintains its right during the transition period to retain its merchant function and serve as a supplier option for all customer classes. No later than six years from the effective date of the ARP, the parties will meet and revisit the continuing role of NIPSCO as a merchant (provider of retail services) in a fully unbundled environment.
4. Supplier of Last Resort. NIPSCO will remain the Supplier of Last Resort (SOLR). SOLR services may include backup natural gas supply (commodity), backup transportation capacity, appropriate storage resources and services related to delinquent accounts.

5. Maximization of Underutilized Upstream Core Portfolio Assets. During the transition period, NIPSCO will attempt to maximize the utilization of any underutilized upstream core portfolio assets. These assets are (1) contracted capacity for transportation and storage and (2) contracted gas supply acquired in order to provide reliable service to the utility's core market. NIPSCO will share with its core customers the recovered revenues of the underutilized assets at a level of 85 percent to core customers and 15 percent to NIPSCO.
6. Gas Cost Incentive Mechanism (GCIM). The parties to the settlement have agreed to a Gas Cost Incentive Mechanism that rewards and penalizes NIPSCO for its supply acquisition performance when compared to a market standard benchmark. The tolerance and sharing bands agreed to by the parties are established for an initial two-year period. At the conclusion of the two-year period, the appropriateness of the bands, the derivation of the benchmark and the GCIM calculations shall be subject to an annual review on a confidential basis.
7. No Recovery of Pilot Program Transition Costs. NIPSCO has agreed not to seek recovery of any transition costs resulting from the implementation of the two-year residential pilot program.
8. Implementation of Gas Marketing Affiliate Guidelines. The parties have agreed to a set of marketing affiliate guidelines that will be used to govern transactions between NIPSCO and any gas marketing affiliates. The term marketing affiliate shall mean a company, partnership or other entity within a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas and/or provides gas-related services.
9. Embedded Cost-of-Service Study. NIPSCO shall provide the parties with an embedded cost-of-service study for all services not subject to competition no later than six months after the end of the transition period and in no event earlier than January 1, 2000.
10. Earnings Test Applies. NIPSCO agrees that all revenues generated under the terms of the stipulation and agreement shall be subject to Indiana Code 8-1-2-42(g)(3)(C), the currently enforced earnings test in gas cost adjustment (GCA) proceedings before the IURC.
11. Rate 330 Sales Reviewed in GCA Proceedings. NIPSCO agreed to allow the OUCC and its consultants upon request to inspect, on a confidential basis, information regarding the sales under Rate 330, Large Volume Negotiated Sales Service, including related contracts and supply resources. The OUCC will report if any of these sales have adversely impacted the GCA and whether further investigations are warranted.

b. ProLiance

ProLiance is an Indianapolis-based marketer of energy and related services that was formed in March 1996 by affiliates of Indiana Energy and Citizens Gas, which assumed the gas supply and portfolio administration services for the two utilities. ProLiance administers the utilities'

transportation and storage contracts, and procures gas and transportation in the marketplace on behalf of the two utilities. ProLiance also develops supply plans for the utilities' review, schedules supply deliveries to the citygate and develops capacity portfolio plans for the utilities' review. Additionally, ProLiance provides gas sales, administration and marketing services to the customers of the utilities' marketing affiliates.

In Cause No. 40437, 20 industrial customers served by the two utilities petitioned the Commission to disapprove the contracts and agreements between Indiana Gas and Citizens Gas relating to ProLiance. The petitioners were later joined by the OUCC and the Citizens Action Coalition. For the petitioners, the central issue was whether the contract between Indiana Gas and ProLiance should be disapproved as not in the public interest for the following reasons: 1) the lack of competitive bidding and the reasonableness of contract terms; 2) alleged violation of the terms of a prior settlement agreement regarding capacity release; 3) the unapproved transfer of alleged utility assets and functions; 4) the misallocation of the benefits of operational consolidation of the utilities; 5) the circumvention of Commission regulation and oversight; and 6) alleged anti-competitive effects on the marketplace.

The complaint was originally filed on March 29, 1996, and amended on June 7, 1996. On September 12, 1997, the IURC denied the complaint. In its order, the Commission ruled that the agreements by which the utilities created ProLiance are in the public interest, in part, because efficiencies gained by consolidating the gas supplies of the two utilities have caused gas rates to decrease for each utility. The Commission advised the utilities, however, that the Commission would be taking some of the concerns raised in the complaint into account when scrutinizing future gas cost adjustment filings.

The Commission ruled that because ProLiance is not a public utility within the meaning of Indiana law [I.C. 8-1-2-1(a)], it does not fall under the jurisdiction of the Commission's regulatory authority. The Commission disagreed with the petitioners' assertion that Indiana Gas and Citizens Gas had improperly transferred utility assets to ProLiance and agreed with the utilities that they had assigned only the purchase obligations for the gas supply portfolio to ProLiance and had kept the traditional role of delivering the gas to end users.

The Commission also disagreed with the petitioners and intervenors that the utilities had purposefully circumvented the Commission by forming ProLiance and had formed the marketing agent in secret. The Commission found ". . . there was nothing in the formation of the alliance which demonstrated bad faith or an intent to circumvent Commission regulation or motives against the public interest."

Independent marketers, who also intervened in the case, claimed that the utilities should have sought a marketer through a Request for Proposal rather than by forming their own affiliated

marketing agent. The intervening independent marketers purchase natural gas on the open market and resell it to utilities and large industrial customers. The marketers claimed that because ProLiance is closely aligned with Citizens Gas and Indiana Gas, it already has a market presence among the long-standing customers of the two utilities, which impedes fair competition. The Commission found that those markets were not adversely affected by consolidation of the supply arrangements of the two utilities. The Commission indicated that it would be scrutinizing the utilities' quarterly gas cost adjustment filings to determine whether the customer benefits, as represented by the utilities in this case, continue. The Commission found ". . . experience under the current agreements may indicate that their actual operation does not comport with the public interest even though we find that they do so now. Actual experience may compel an investigation on the Commission's own motion in the future, if the representations of the respondent utilities' witnesses do not bear out."

Also in its order, the Commission admonished Indiana Gas and Citizens Gas, saying that although it would not disapprove the formation of the marketing company, it would have preferred the utilities to seek Commission approval of the new arrangement through an alternative regulatory plan.

c. Residential and Commercial Unbundling Pilot Program Proposed by Indiana Gas

On April 21, 1997, Indiana Gas Company, Inc., sought Commission approval for an experimental program that would give certain residential and commercial gas customers a choice of gas supplier similar to large commercial and industrial customers. Guidelines relating to the utility's relationship with an affiliated business that would market gas to these consumers were also included as part of the filing. The experiment would have taken place in a designated community with up to 34,000 eligible customers, and would have lasted for an initial term of two years with a possible two-year extension. Under this program, each customer choosing another supplier must be represented by an aggregator, who would procure natural gas supplies for a group of customers. Indiana Gas would have then supplied firm transportation service to those customers choosing another supplier. The customer's bill for gas would have consisted of Indiana Gas's transportation charge plus the cost of the gas from the aggregator.

Indiana Gas sought approval of this program without a hearing, using the Commission's 30-day filing procedure. The 30-day filing procedure is used by utilities to gain approval of certain types of non-controversial proposals in a more expeditious and less costly manner than a formally docketed case. The Commission may grant approval of certain filings in this summary method. However, such exceptional approval is contingent upon Commission review, taking into account any objections from the OUCC or other interested parties. Both the OUCC and the Citizens Action Coalition objected to the filing and the Commission rejected the proposal as a 30-day filing on May 8, 1997. In its decision, the Commission stated the rejection was due to Indiana Gas's attempt to use the 30-day filing procedure, not the merits of the proposal. The Commission did encourage Indiana Gas to

address the concerns of the objecting parties and agreed to schedule a public meeting to aid the process, if Indiana Gas so desired. Indiana Gas requested the public meeting, which was held on May 28, 1997.

IV. SUMMARY OF STATE COMPETITION INITIATIVES

A. State Competition Initiatives in Electricity

Electric utility restructuring has been an active issue in most states since the last Energy Report to the Regulatory Flexibility Committee of the Indiana General Assembly. Thirteen state legislatures considered some sort of restructuring-related legislation. Many of these bills were abandoned before a vote was taken, while others were voted down. Colorado, Connecticut, Illinois, Massachusetts, Nevada, South Carolina, Texas and Vermont all had restructuring legislation in the works that was either abandoned, left pending at the end of session or failed upon vote. Restructuring-related legislation was approved in Maine, Montana, Rhode Island and Oklahoma. In Oklahoma, the legislation established a Task Force to further study electric utility restructuring issues. In Maine, Rhode Island and Montana the legislation provided for definite steps towards customer choice.

State regulatory commissions are also busy addressing restructuring issues, although they are in very different stages in the process. Commissions in California, Pennsylvania, Michigan, Wisconsin and other states have been wrestling with the details of restructuring. These commissions are in the process of evaluating utility-filed restructuring plans or dealing with specific restructuring issues such as stranded cost and securitization. Other commissions are just beginning to formulate a plan for addressing restructuring. The commissions in Arizona and North Dakota have recently established guidelines and procedures to begin the restructuring process. The Maryland Commission, after rejecting customer choice two years ago, has decided to reconsider the issue, responding to changes in the electric utility industry.

A few states have tried to approach the restructuring issue through a collaborative process. In Louisiana, Governor Mike Foster tried to defuse a media war by urging the parties to negotiate a settlement on restructuring issues. In June 1997, talks ended without a resolution. A formal proceeding will now be necessary to address restructuring in Louisiana. Alternatively, the Wyoming Public Service Commission used a collaborative process that resulted in a White Paper addressing the restructuring issues. One of the recommendations was that a comprehensive study of the economic impacts of restructuring should be performed. Recently, the New Mexico Public Utility Commission began a collaborative process on restructuring, in which participants submitted proposals on how the process should proceed.

Many state legislative bodies and commissions are still in the "educational" phase of addressing electric utility restructuring. Task forces and study groups have been established by either the state

commission or legislative body in eleven states. Several states have separate groups established by both the state commission and the state legislative body. The groups range from informal monitoring bodies to formally established groups with responsibilities to propose legislation or procedures for initiating retail competition. In 1995-96, the IURC conducted educational forums regarding restructuring the electric utility industry.

Only four states have not addressed electric utility restructuring issues in the last twelve months. Alaska and Hawaii, due to their unique geographical location and lack of competitive alternatives, may never feel the need to consider restructuring or customer choice. Early in 1996 the Alabama legislature gave the state utility commission authority to review power contracts signed by Alabama Power customers with new suppliers and to order stranded cost recovery, where appropriate. This legislation will sunset once comprehensive electric utility restructuring is addressed in Alabama, but there has been no action taken yet on the issue. The South Dakota legislature and the state's regulatory commission have shown no interest in restructuring.

The following discussion highlights some of the significant legislative and commission actions in Indiana's four neighboring states and throughout the United States during the previous twelve months. Appendix 3 presents a summary of restructuring activities by state.

- Illinois -

In spring 1997, the Illinois legislature considered electric utility restructuring in Senate Bill 55. While the bill was overwhelmingly passed in the House, Senate president James Philips refused to bring SB 55 up for a vote before the legislative session ended. Philips claimed the bill was too complex to be rushed at the end of the session. It is expected that SB 55 will be reconsidered during the "veto session" this fall.

Throughout the summer the Illinois Commerce Commission (ICC) held a series of meetings designed to gather input for a report to the state Senate on electric utility restructuring. The ICC had been instructed to conduct an independent analysis of the issue of electric deregulation with particular emphasis on Senate Bill 55.

On August 18, 1997, the Illinois Commerce Commission released its report, severely criticizing Senate Bill 55. The ICC stated that "while SB 55 establishes a five-year timetable for offering access to alternative suppliers, the length of the stranded-cost recovery period, the inadequacy of stranded-cost verification, and other anti-competitive provisions of the bill will render the freedom to choose an illusion for the great majority of Illinois citizens."

"The balance struck by SB 55 leans too heavily in favor of the utilities," the commission added. The bill gives a competitive edge to electric utilities at the expense of alternative retail power suppliers. Customers of alternative power suppliers will be required to pay a fixed delivery charge,

a fixed transition charge and a fixed decommissioning charge, in addition to the price of energy, while a utility's customers could receive a discount on all of those items. As a result of this pricing flexibility, utilities could prevent competitors from entering the market. The ICC also criticized SB 55's failure to unbundle power supply rates from delivery service rates for utility customers, thus restricting a consumer's ability to compare the prices of service offerings of competing suppliers.

It is unclear what effect the ICC's report will have on the Senate's consideration of Senate Bill 55 during the "veto session" this fall.

- Michigan -

On June 5, 1997, the Michigan Public Service Commission (MPSC) approved a state restructuring plan that opens Michigan's electric industry to competition.

Beginning later in 1997, the plan requires each utility to make available to all customers on a first-come, first-served basis a block of direct-access capacity equivalent to about 2.5 percent of the utility's load. Under the provisions of the MPSC's order, utilities will be required to add another 2.5 percent block each year through 2001. By 2002, any customer in the state that wants choice of supplier will be eligible to receive it.

If, during the years before 2002, customers with load demand greater than the 2.5 percent block allowed to switch per year want to select alternative suppliers, customers will be required to submit an exit bid. The bid will reflect the amount of stranded costs the customer is willing to pay in order to get access to an alternative supplier. The commission will select the highest bidders until the 2.5 percent allocation is filled for that year. Once all customers become eligible for choice, stranded costs will be determined on a comparison of actual generation cost versus the market price of power.

In August 1997, the Michigan Attorney General, the Residential Ratepayer Consortium and the Association of Businesses Advocating Tariff Equity petitioned the Ingham County Circuit Court to stop deregulation proceedings until the MPSC determines it has authority to mandate direct access.

- Ohio-

The Joint Select Committee on Electric Industry Restructuring missed a self-imposed October 1, 1997, deadline to prepare a consensus restructuring proposal. It now appears that the report may not be completed until late December 1997. The most divisive issue had been stranded cost recovery.

The Alliance for Affordable Power, which includes two of Ohio's highest-cost electric companies, Centerior Energy and Ohio Edison, has threatened to sue the state for damages if the competition proposal does not provide for stranded cost recovery. The Alliance claims that the denial of transition costs for electric companies could damage their financial integrity to the point where they would be driven into bankruptcy.

In a related development, Centerior and Ohio Edison were joined by American Electric Power, Cinergy and Dayton Power & Light in urging the Public Utility Commission of Ohio (PUCO) not to release company-specific stranded cost figures to the legislative panel. The utilities argued that the commission's notion of preparing stranded cost estimates for the committee is fraught with problems and is not an effective use of time or resources and could well be inconsistent with the policy ultimately established by the General Assembly.

In response, PUCO Chairman Craig Glazer said the commission will give legislators a range for stranded costs but no specific numbers for individual utilities.

- Kentucky -

As a low-cost state, Kentucky has shown little interest in restructuring its electric utilities. In December 1996, the Kentucky Public Service Commission initiated a series of informal, one-to-one, fact-finding conferences with utilities and consumer groups to discuss the issues and concerns surrounding electric restructuring. No formal proceeding or order was expected to result from these meetings.

- California -

On December 20, 1995, the California Public Utilities Commission (CPUC) approved a comprehensive restructuring plan that allows retail direct access within five years. Generation will be competitive while T&D will continue to be regulated to ensure safety, reliability, environmental protection and equal access for all power suppliers. The plan also called for the formation of a state-wide Independent System Operator (ISO) to ensure reliability and a Power Exchange (PX) to provide a "spot" market.

In April 1996, California's three IOUs filed for Federal Energy Regulatory Commission (FERC) approval of an ISO and a state-wide power exchange. In November 1996, the FERC issued a favorable order concerning the conceptual filings to set up the ISO and PX and established a March 31, 1997, filing date for the utilities to file Phase II testimony addressing the details of the proposals.

On September 23, 1996, Assembly Bill 1890 was signed into law. This legislation supports deregulation of California's power industry and opens retail competition beginning January 1, 1998. The legislation, which generally follows the CPUC's plan, requires a 10 percent rate cut on January 1, 1998, for residential and small commercial customers and a further 10 percent reduction expected by April 2002. Special bonds may be issued to finance the rate reductions. Rates for large industrial and agricultural customers will remain frozen until 2003. No customer will experience a rate increase. This rate freeze, coupled with the five-year limit on the competition transition charge (CTC)[3] and a

[3] Competition Transition Charge (CTC): A non-bypassable charge applied to all customers, designed to allow a utility to recover stranded costs.

reduced return on equity to 90 percent of cost of debt allowed on generating plants, will result in some sharing of stranded costs between customers and investors. All electricity sellers, brokers, marketers and aggregators will have to register with the state, and a process for investigating consumer complaints is to be established.

On December 20, 1996, the CPUC adopted a plan to help expedite restructuring. The plan calls for the adoption of direct access tariffs by October 1997, with a final decision on transition costs to be made by October 22, 1997.

The CPUC began hearings May 19, 1997, to determine the stranded costs that utilities will be eligible to recover through the CTC when electric restructuring begins in January 1998. The utilities estimate that $28 billion will be rendered uneconomic by the market and thus necessitate recovery through the CTC. An independent audit report compiled for the CPUC questioned $8 billion of the utilities' $28 billion estimated total stranded assets. The CPUC concedes it will be virtually impossible to determine the exact amount of utilities' stranded assets until the new market begins in January and the power exchange price is known.

- Massachusetts -

In February 1997, the Massachusetts Department of Public Utilities (MDPU) approved New England Electric System's (NEES) restructuring settlement agreement. The agreement will allow NEES to sell off about 4,000 MW in fossil fuel and hydroelectric generation. NEES's subsidiary, Massachusetts Electric, will become a distribution company and will recover stranded costs through a 2.8 cents/kWh wires charge. Massachusetts Electric will continue to offer power for seven years through a standard offer at a 10 percent rate reduction. NEES's plan had widespread approval, with more than 14 groups supporting it, including independent power producers and environmentalists.

Also in February 1997, Massachusetts Governor William Weld filed a restructuring proposal with the state legislature. The bill is modeled after the MDPU's recent restructuring rule. The governor's proposal includes retail competition for all customers by January 1, 1998; offers stranded cost recovery and unbundled rates; continues monopoly status for distribution companies and creates a standard offer rate, similar to MDPU's rule. In addition, the proposal includes environmental rules for all suppliers doing business in the state; financial incentives for utilities to renegotiate purchase power contracts; a 10 percent rate reduction for five years and less stringent power plant siting rules.

The Massachusetts legislature must take action in 1997 for retail wheeling to begin January 1, 1998. The governor's bill is one of more than 30 electric industry proposals before the legislature. In addition, a special legislative committee is investigating restructuring and plans to release a report soon.

- New Hampshire -

On February 28, 1997, the New Hampshire Public Utilities Commission (NHPUC) issued its final electric utility restructuring plan. The plan described the commission's approach to move electric rates toward the regional average, thus making businesses more competitive and providing relief to residential customers while still assuring reliability of service. Specific provisions of the plan included:

- Restructuring is to begin January 1, 1998.
- Utilities are required to file restructuring plans by June 30, 1997.
- Distribution companies would remain regulated.
- Low-income assistance would be funded by a systems benefit charge that would be added to the average monthly customer bill.
- Integrated resource planning and energy efficiency programs would no longer be funded by ratepayers. The market would more economically provide these services.
- Environmental and renewable energy goals would be met by requiring suppliers to disclose the sources and impacts of the generation sold.
- Residential and small commercial customers would have access to "default service" that would be administered by the local distribution company (LDC).

In response to the commission's plan, Public Service of New Hampshire (PSNH) filed a lawsuit claiming that the stranded cost provisions in the plan were unconstitutional. The Court rejected the state's arguments that its plan was not yet final and the federal court should abstain from interference in the regulatory process at this time. The Court stated that the legislative process of restructuring the electric utility industry was completed with the NHPUCs issuance of its restructuring plan.

The Court noted that the issues raised by PSNH covering the new structure of the electric industry and principles of cost recovery involve constitutional rights and not technical issues that normally would be handled by state regulators. The Court especially focused on PSNH's claims that the plan would push it into bankruptcy and that the state has violated an agreement with its parent, Northeast Utilities, on recovery of costs related to NU's 1992 takeover of PSNH. The NHPUC plan provides PSNH with only 60 percent recovery of stranded costs, based on a controversial regional averaging approach, and a 19 percent rate cut.

In an effort to solve the dispute outside the courts, New Hampshire Governor Jeanne Shaheen and PSNH agreed to use former federal transportation secretary William Coleman to mediate their legal dispute over the state's electricity restructuring plan. The U.S. District Court stayed the PSNH lawsuit against the plan while the mediation effort was proceeding.

On September 2, 1997, the state of New Hampshire and PSNH ended their mediation efforts without reaching agreement on key restructuring issues. The failure means the two sides will now return to a federal district court to litigate the controversial state restructuring plan.

The prospect of continued court action makes it unlikely that the state can implement retail choice as planned on January 1, 1998, and may even miss the July 1, 1998, deadline set under the state restructuring law passed in May 1996. It is also likely that the legal battle over the New Hampshire plan may result in court rulings on restructuring issues that will have national implications. New Hampshire is the only state so far where a final deregulation plan is being challenged by a utility in court, and PSNH has raised several constitutional questions about New Hampshire's rights to impose a new regulatory system and stranded cost recovery scheme that have not been tested yet.

- Pennsylvania-

PECO Energy and Pennsylvania Power & Light are seeking $11.4 billion in stranded costs through restructuring plans filed with the Pennsylvania Public Utility Commission (PPUC). The plans were submitted in April 1997 under the Electricity Generation Customer Choice and Competition Act, which requires utilities to phase in retail access between 1999 and 2001.

PECO Energy asked to recover $6.8 billion in stranded costs, which stem largely from its 3,900 MW nuclear capacity. Through a 120-day securitization filing the company applied for "transition bonds" to refinance $3.6 billion of the $6.8 billion total at lower interest rates.

On April 14, 1997, PPUC Administrative Law Judge Louis Cocheres recommended against the approval of PECO's securitization plan to recover stranded cost. PECO appealed to the Pennsylvania Public Utilities Commission to approve its plan contrary to the judge's recommendation.

In response, the commission ruled that PECO could collect $1.1 billion in stranded costs. As a result PECO will be able to proceed with the issuance of the "transition bonds" that will allow refinancing at lower rates. PECO had originally requested $3.6 billion in the securitization filing but the PPUC decided that the 120-day securitization proceeding did not permit a sufficiently thorough review and only allowed the "non-controversial" $1.1 billion portion of the stranded costs.

The commission's decision on the securitization filing has the effect of guaranteeing the stranded cost recovery of at least $1.1 billion of PECO's proposed $6.8 billion in stranded costs. Intervenors have appealed the PPUC's decision. A final decision on PECO's full stranded costs is not expected until the end of the year.

The PPUC held hearings on Pennsylvania Power & Light's request for $4.6 billion in stranded cost recovery earlier this summer. Other Pennsylvania utilities filed their restructuring plans throughout the spring and summer of 1997.

1. Retail Competition Electricity Pilot Programs

As of summer 1997, five states had established retail competition electricity pilot programs: Illinois, New Hampshire, Massachusetts, New York and Washington. These programs have provided valuable information for not only the states involved, but those considering retail competition. Consumers, utilities and marketers have experienced first-hand the advantages and disadvantages of competition.

Results from the pilot programs have yielded some general findings.[4] As expected, saving money was the dominant factor in determining customer participation. In many cases, customers wanted to switch to a competitive supplier because of high retail rates charged by their traditional utility. There was also an unexpected strong interest in "green power" (e.g., renewable energy sources). In the Massachusetts pilot program, for instance, 31 percent of the customers chose to purchase green power.

Larger customers were particularly receptive to retail competition. Despite some instances where customers were dissatisfied with savings or did not understand the program, customers were generally content. A survey conducted in New Hampshire indicated very strong customer satisfaction with the program and retail competition, despite early problems attributed to lack of customer education. All of the pilots provided evidence that customer education was essential.

Aggregation of different customer classes proved successful. In many cases, aggregators offered to provide electricity below cost in an effort to attract customers, gain experience and establish name recognition.

Hourly load research data was essential for estimating each customer's hourly electric usage. Utilities involved in full competition will have to develop accurate customer load profiles, and it may become necessary to install more sophisticated meters that can measure hourly demand.

Several states decided that "codes of conduct" were necessary to provide assurance that a parent utility would not favor its marketing affiliate. The states either adopted or modified the FERC's code, which includes requirements such as separation of utility staff and costs from marketing affiliates and nondiscriminatory access to customer information.

Most commissions saw a need to protect customers from improper conduct by energy suppliers. These commissions determined that requiring marketers to be certified by meeting certain standards would provide some guarantee of reliability for customers. Standards suggested include eligibility rules, grievance procedures, warranties and other consumer protection measures. It is important,

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[4] Edison Electric Institute, Retail Pilot Programs: The First Six , 1997.

however, that the certification process not be so burdensome that it creates a barrier to entry that discourages competitors.

Studies indicate that customers are interested in obtaining unbundled service. Because most of the pilot programs did not unbundle services, additional pilots that give other entities the opportunity to provide metering, billing and customer service would be useful. These pilots would help determine whether is it feasible for services to be provided by a company other than the local utility.

Details of electric pilot programs are found in Appendix 4.

B. State Competition Initiatives in Natural Gas

Despite the FERC's effort to encourage competition in the wholesale gas markets since the mid-1980s, there has been very little movement by states to promote retail competition. As a result, most states currently only allow large customers (e.g., industrial or electric utilities) to purchase "unbundled" gas services.[5] Some states, for example Iowa, unbundled services to residential customers in the mid-1980s. In Iowa's case, however, limited profit potential has resulted in a lack of marketer interest that has hindered the development of effective competition.

In the last two years, 12 states have asked LDCs to propose plans to offer unbundled service to smaller customers, at least on an experimental basis.[6] The legislature and/or the state commissions in ten other states have expressed their intention to allow all customers to have their choice of gas suppliers by 2000.[7] As early as 1991, California offered small and medium-sized customers entry to competitive gas markets through its Core Aggregation Transportation program.' New York was among the first states to restructure LDC operations down to the residential level. On May 1, 1996, Brooklyn Union became the first LDC to give all customers the option to purchase natural gas from third-party sources. Maryland approved small customer unbundling experiments by the largest LDCs, beginning in November 1996. The New Jersey unbundling program is interesting because of the tax issues it has raised. Recent developments in Illinois, Ohio, Pennsylvania and Wisconsin are also noteworthy. Appendix 5 summarizes recent actions taken in other states.

Each of the previously mentioned states is a prime example of how some PUCs are promoting retail competition for residential and other smaller customers. Increasingly, state commissions have

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[5] In its simplest form, unbundling entails the separation of specific services into various components. In the natural gas industry, service unbundling could involve breaking down some of the following services: metering, billing, back-up services, interruption insurance, storage, balancing services, hedging instruments and others.

[6] ISSUE BRIEF, American Gas Association, April 18, 1997, page 1.

[7] ISSUE BRIEF, American Gas Association, April 18, 1997, pages 2 and 3.

started to wrestle with the fundamental question of how to offer consumers the greatest array of choices, and at the same time maintain reasonable rates and ensure service quality. To reach these objectives, state commissions have taken different approaches. Some state commissions have sought to reduce rates as much as possible, in the belief that a competitive market will ensure service quality. For example, California no longer requires small customers to take back-up service. The California Public Utilities Commission believes that the market will weed out marketers that are unwilling or unable to perform during peak demand periods. Other states have sought to maintain service quality, perhaps at the cost of higher rates. The New York Public Service Commission, for instance, requires small customers to take backup service from the LDC regardless of the marketer from which they obtain gas. The Maryland Public Service Commission requires commercial customers who consume less than 2 million cubic feet per year to pay a flat fee for standby service. Most states, as a precursor to competition, have instituted codes of conduct to govern the relationships between regulated LDCs and their non-regulated affiliates, as well as between LDCs and competing marketers and aggregators.

State efforts to provide smaller residential and commercial customers service choice by providing access to unbundled gas services are gaining momentum. Many states are actively examining or implementing some form of retail unbundling which will give smaller LDC customers the same access to competitive gas markets already enjoyed by larger customers.

LDCs originally began offering unbundled service to retain large industrial and electric utility customers in the face of stiff competition from interstate pipeline companies. End-use prices to different customer classes provide evidence that small customers received significantly fewer benefits from the transition of the wholesale market to competition. Between 1990 and 1995, prices to residential customers have fallen 10 percent, from $6.67 per thousand cubic feet (1995 dollars) to $6.06 per thousand cubic feet. In contrast, over the same period, prices to industrial customers fell in excess of 24 percent, from $3.37 per thousand cubic feet to $2.71 per thousand cubic feet.

State regulators and consumer groups want to extend the benefits of retail competition to smaller LDC customers. However, they face many challenges along the way, including appropriate pricing of services, what services should be unbundled, service reliability, corporate structure and the allocation of costs associated with the transition to the competitive market. Also, although aggregate savings from unbundling and greater competition could be considerable, in terms of the price paid for gas by small consumers, questions abound about the magnitude of the saving. For example, to satisfy the obligation to provide secure supplies on demand, many state commissions are requiring small customers to continue to take backup service from their LDC. The requirement to take this expensive service could offset any savings from unbundling and prevent the formation of a competitive market.

As unbundling proceeds, transition costs will continue to accumulate. Some LDCs may find themselves paying for long-term firm interstate pipeline capacity they no longer need. How these costs are apportioned among interstate pipeline companies, LDC shareholders and the different classes

of LDC customers will significantly affect the savings to individual stakeholders. However, many in the industry believe that the long-term benefits of retail competition will far outweigh any short-term costs incurred along the way.

V. SUMMARY OF FEDERAL LEGISLATIVE INITIATIVES

In the past two years, there has been an increased interest in electricity restructuring at the federal level. While no restructuring bill is expected to pass Congress this session, enough bills have been introduced in both the House and the Senate in 1996 and 1997 to place the issue in a key position for the coming session.

Complicating the issue of federal legislation is the difference in priority members of the House and Senate give to mandating restructuring by a date certain. Three of the six comprehensive bills introduced require states to implement retail competition by a specific date.

Representative Dan Schaefer (R-CO) has conducted nearly 20 hearings on restructuring. His energy and power subcommittee of the House's Commerce Committee may schedule a mark-up session for November 1997 if there is enough support for his bill.

Much of the initial legislation introduced at the federal level focused on repealing mandatory Public Utility Regulatory Policies Act 1978 (PURPA) purchases from non-utility generators, an objective state legislation could not accomplish. After states such as California, Pennsylvania and Rhode Island passed customer choice legislation, however, federal bills began to incorporate the concepts of retail choice. Federal legislators became worried about reciprocity and "cherry picking" if some states enacted choice and others did not.

In past and present bills, restructuring has been a bipartisan issue. The Clinton administration has said it will release a federal restructuring bill this year, but what it will contain is unknown at this point. At the present time the bill is being circulated within the administration for inter-agency review.

Appendix 6 provides an overview of the eight restructuring bills introduced into Congress since last year's Report.

VI. FERC ACTIVITY

A. Revised Merger Policy

In January 1996, the FERC requested comments on how it should evaluate mergers.[8] In December 1996, the FERC issued a revised merger policy statement. This nonbinding policy statement is to be followed in 1997 by a rule that will add details to the filing requirements. To date, however, the merger rule has not been issued by the FERC. One of the main purposes of the revised merger policy is to speed the review process time; instead of 12 to 15 months, the FERC hopes to cut that time in half.

The new policy focuses on just three of six factors that the FERC previously used to assess mergers. The most important factor is the merger's effect on competition, followed closely by the protection of ratepayers. The third factor is the transaction's ramifications for effective state and federal regulation.

To assess a merger's effect on competition, the FERC will employ the five-pronged antitrust guidelines used by the Department of Justice and the Federal Trade Commission. These involve deciding whether the merger concentrates generation too heavily; increases market power; produces efficiencies that offset market power; allows competitors into the market; and involves a company that otherwise would fail if the merger did not occur. The new policy promises to give the FERC the information it needs to assess market power particularly on the important issue of transmission constraints.

The FERC applied its new merger policy to the proposed merger of Wisconsin Energy Corp. and Northern States Power Co. to form Primergy. In May 1997, the FERC directed the two parties to pursue ways of mitigating market power, and it made the explicit suggestion of divestiture of generating assets. Perhaps the most important issue was the overwhelming post-merger generation concentration on both sides of a single 345 Kv interface between two reliability regions. The FERC applied its new measure for market power, the Herfindahl-Hirshman Index (HHI), and found that Primergy's market share would be 42 percent to 47 percent after the merger. It found that the increase in the HHI justified a presumption that the merger was likely to create or enhance market power.

In directing the parties to pursue their own settlement rather than prescribe the solution itself, or give it an outright approval or rejection, the FERC attempted to give the parties another chance at the merger, and let the parties tailor an optimum solution uniquely suited to them. Instead of trying

[8] The IURC filed comments on the FERC's Notice of Inquiry into merger policy on May 1, 1996. The Commission recommended that FERC adopt a more rigorous approach to electric utility industry mergers and acquisitions. The IURC also urged the FERC not to approve mergers that would undermine the ability of states to fairly and reliably regulate local markets.

again, however, two days after the FERC decision the two utilities decided against pursuing the merger any further. The FERC Chair stated on the day of the decision that: "[the commission is] resolute that we cannot find that mergers that increase [wholesale] market power to unacceptable levels are in the public interest."[9]

The FERC also expanded on its deference policy regarding state jurisdiction and retail competition. The FERC will examine a merger's effects on retail competition only if a state says it lacks statutory authority to address the issue adequately. This issue was argued in the merger of Baltimore Gas & Electric and Potomac Electric Power. The FERC trial staff recommended both generation divestiture and transmission upgrades to avert potential retail market power, but Maryland state regulators argued that the consideration of retail market power is a state concern. In April 1997, the FERC approved the merger without conditions.

One important aspect of the merger policy to note is that while it clearly applies to horizontal mergers between two electric utilities, it is somewhat unclear if it will apply to so-called convergence mergers. Convergence mergers are non-traditional mergers that do not involve two or more vertically integrated electric utilities. Some examples include an electric utility with an adjacent or overlapping gas distributor; an electric utility with an interstate pipeline company or power marketer; a power marketer acquiring an independent power producer's generating assets; or an electric utility combining with a non-energy service provider, such as a communication or electronic security firm.[10]

In a decision on April 30, 1997, the FERC asserted authority over three convergence mergers.[11] In all three cases, the parties had earlier asked the FERC to disclaim jurisdiction. The FERC believes that the statute is clear and that as a matter of law and as a matter of policy the FERC has jurisdiction. The FERC laid out its interpretation in the Enova-Pacific Enterprises order. It states that if one company in a merger has a power marketer or any other operation defined as a public utility under section 203 of the Federal Power Act (FPA), then the merger will fall under the FERC's jurisdiction. If the merger raises no competitive concerns, then the FERC will require less information from the parties and will attempt to approve the union promptly.

The FERC stated in the Enova-Pacific Enterprises order that it is not asserting jurisdiction over the merger of the holding companies themselves. Instead, the FERC asserts jurisdiction over the proposed transfer of control of public utility jurisdictional facilities to ensure that this transfer of

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[9] *Inside F.E.R.C.*, May 19, 1997, p. 13.

[10] Examples of such announced mergers include: Houston Industries-Noram; Enova-Pacific Enterprises; Texas Utilities-Enserch; Enron-Portland General Electric; and Southern California Gas-San Diego Gas & Electric.

[11] The three mergers are Enova Corp-Pacific Enterprises; NorAm Energy Corp.-Houston Industries Inc.; Morgan Stanley Capital Group Inc.-Dean Witter, Discover & Co.

control is consistent with the public interest. The FERC is looking beyond the corporate form of the transaction, and in cases where the control of a public utility is transferred from one corporate entity to another, the FERC will regard the parent and subsidiary as one company.

One FERC commissioner admitted that convergence mergers will require the FERC to adjust its merger analysis, particularly with respect to the horizontal market power of the merged company; i.e., if the merged companies sell a common product in a common geographic market. The merger policy statement does not provide a clear picture of how the FERC will tackle this issue, but it does provide some limited preliminary guidance. For example, if the geographic markets of the two merger partners do not overlap, there will not likely be a market power concern.

Along with horizontal market power issues, the FERC is also concerned with vertical market power in convergence mergers. The FERC's developing policy on this issue was articulated in its June 1997 order conditionally approving a union between Enova Corp. (parent of San Diego Gas & Electric Co.) and Pacific Enterprises (parent of Southern California Gas Co.). Unlike other recently approved convergence mergers,[12] this merger involved overlapping geographic territories. Because Pacific owns very little electric generation, there were no horizontal market power concerns. However, because Southern California Gas controls a very significant amount of the pipelines delivering gas to potential competitors' electric generation plants, there was a significant vertical market power concern.

The FERC's concern was that the combined company could use its control of natural gas pipelines to exert market power in electric generation. After reaching this conclusion, the FERC deferred the issue to the CPUC because the pipeline in this case is under state regulatory authority. However, the FERC did spell out both the analysis it will use to examine market power, and the remedies to alleviate market power that the state commissions can implement and upon which the FERC has conditioned its approval of the merger.

The FERC has laid out three types of general competitive concerns raised by vertical mergers. First is the potential of the merged company to deny rival firms access to fuel inputs or to raise their input costs. Second is the prospect of increased competitive coordination by the merging firms. Third is the potential for regulatory evasion.

In the Enova-Pacific case, the FERC found the first two concerns were present. The proportion of generation capacity served by Southern California Gas is high enough to effectively limit wholesale power customers' range of alternative electricity suppliers. In addition, the merger would very likely discourage entry by gas-fired generators. The FERC also found that the merged company has the

[12] Enron Corp-Portland General Corp.; Duke Power-Pan Energy Corp.; NGC Corp-Destec Energy Inc.

incentive and ability to foreclose competing generators from the delivered gas market or raise their delivered gas cost resulting in higher electricity prices in the wholesale power market.

In order to mitigate the market power concerns, the FERC imposed three measures, but it can only enforce them in part. First, it ordered San Diego Gas & Electric and marketing affiliate Enova Energy Inc. to file standards of conduct that comport with those required in cases involving approval of market-based rates for electric utility marketing affiliates.

Second, it initiated its Order 437 requirements which impose a code of conduct on pipelines and their gas marketing affiliates to ensure nondiscriminatory treatment for unaffiliated marketers and other shippers.

Third, it revamped Southern California Gas Co.'s electronic bulletin board. As a result, San Diego Gas & Electric's nominations for transportation of gas to supply its wholesale generation activities must be conducted on Southern California Gas Co.'s Electronic Bulletin Board just like any other third-party shipper. The FERC noted that the CPUC would need to accept and enforce the application of the requirements to the merging partners. This case has made clear how the federal and state authorities will need to work together and complement each other for effective regulation of mergers.

B. Approval of California Restructuring Plan

In a series of three orders, the FERC approved the restructuring plan of California. In its first two orders in the complicated proceeding, the FERC addressed the dividing line between state and federal jurisdiction and approved the overall restructuring framework of the PX and ISO. In the third and most substantive order (December 1996), the FERC detailed its thoughts on market power mitigation. The issue of market power in electric generation is one of the most important issues involved in restructuring.

In its order, the FERC agreed with the CPUC that the investor-owned utilities probably have more market power than indicated in the analyses they filed as part of the CPUC's review. However, instead of delaying the process by directing further studies, the FERC told the companies to provide more market-power mitigation measures in future filings.

The order also called for the California ISO to file a detailed plan for monitoring potential market-power abuses. The plan should identify who is responsible for monitoring, the type of information to be collected, criteria for identifying market power and the types of reports that must be filed at the FERC that will allow it to decide if market power exists.

The FERC directed the utilities to explain how auctions for energy and ancillary services will be conducted in order to use the most cost-effective means of providing these services for the PX. Regarding California's competition transition charge, the FERC deferred to the state on stranded-cost recovery, citing its policy adopted in Order 888.

C. Power Pools and ISOs

On February 28, 1997, the FERC issued a blanket order implementing transmission service tariffs for power pools and holding company systems. It mandated that these entities offer a system-wide transmission pricing tariff starting on March 1, 1997.

Within the last year, the FERC has also conditionally approved plans by two groups to form ISOs in their regions. The FERC approved an ISO to be operated by the Pennsylvania, New Jersey and Maryland Power Pool, which cover parts of the mid-Atlantic region. In June 1997, it approved a plan by the New England Power Pool (NEPOOL) to run transmission and other services for the power pool members. The member utilities will relinquish control of their transmission facilities to the ISO, whose role will be to run the system reliably as more power producers and marketers enter the market; administer the pool's transmission pricing tariff; and oversee the NEPOOL power exchange.

VII. RELIABILITY CONCERNS

A modern electric power system can be thought of as one large machine. All components are physically connected, and all can be dramatically affected by events elsewhere in the system. Although there are many devices to prevent them, blackouts can be triggered in a fraction of a second, causing serious damage to the power system and resulting in a loss of power to some areas for days. To help ensure system reliability, the industry has developed a high level of cooperation and coordination among private companies. With restructuring and competition forthcoming, the question now being debated is how electric utilities will maintain the high level of cooperation and coordination necessary for reliability while simultaneously providing greater access to the transmission system and competing for customers.

A. Electric System Reliability Task Force

In the electric industry restructuring debate, one message continually arises: no matter what, reliability must be maintained.[13] Partly in response to two massive power outages that cascaded

[13] A simple definition of reliability is the degree of assuredness with which the utility provides uninterrupted service to customers, and to withstand sudden disturbances such as short circuits or loss of system components, encompassing both the reliability of the generation system and the transmission and distribution system.

through the western power grid in the summer of 1996, the Department of Energy formed the Electric System Reliability Task Force. Its mission is to explore how reliability can be maintained and even improved in the transition to and the final structure of a competitive industry.

In July 1997, the Task Force released an interim report, which focused primarily on issues relating to the bulk power transmission grid and on particular security issues. These issues included questions about the operation and maintenance of the bulk power grid rather than the adequacy of supply or generation. The Task Force urged the FERC to review existing standards established by NERC and its member regional councils that affect operations of the bulk power market. The report stated that the FERC should review the organizational structure and governance of the councils, and that legislation is needed to clarify the FERC's power to oversee and enforce the rules. FERC oversight is needed to ensure reliability standards and to guarantee they are not misused in ways that discriminate against some players in the competitive marketplace. The Task Force stated that the FERC may need additional funding to perform such new responsibilities. The group also found that NERC and its regional member councils should speed efforts to make their governing boards more balanced, and less dominated by a single industry sector.

The Task Force, chaired by former Congressman Philip Sharp, is expected to issue another interim report some time in the fall of 1997. Although opinion is divided over whether competition will enhance or harm reliability, most in the industry believe that reliability will be maintained or improved in a restructured, market-oriented industry.

B. North American Electric Reliability Council

Of course, everyone supports the general concept of reliability. The tougher questions are how will reliability be provided in the future and who will provide it. The North American Electric Reliability Council (NERC), the voluntary industry group that oversees generation and transmission reliability concerns at the present time, has been studying these issues. Last year, NERC formed its own "reliability compliance team," which issued a report in October 1996. The report concluded that instead of voluntary reliability standards, NERC should develop mandatory, contract-based reliability protocols that include sanctions and business incentives to enforce compliance. NERC should possess the necessary authority and power to enforce the contracts and resolve disputes, with the FERC or another government agency acting as the next authority. The report also recommended that all segments of the industry should be subject to NERC's requirements. NERC's structure itself should be replaced with a new system to speed the transition to a competitive industry, the report stated.

In January 1997, NERC voted to make its policies mandatory for all members. NERC has also agreed in principle to phase out the domination of the board by transmission-owning utilities. Currently, NERC is in the process of putting together a blue ribbon panel of outside experts to perform a study and recommend a new structure for itself.

This panel will hold public meetings in September, October and November 1997, and will deliver a final report to NERC's Board of Trustees at its January 1998 meeting. Issues considered by the panel will include: the balance between reliability and commercial needs; the appropriate roles and responsibilities of public and private interests; the impact of possible industry scenarios on reliability; the future of funding those responsible for ensuring reliability; and the future of NERC and regional Reliability Councils.

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IX. ACRONYMS

ARP	Alternative Regulatory Plan
CAC	Citizens Action Coalition
CPUC	California Public Utility Commission
CTC	Competition Transition Charge
EWG	Exempt Wholesale Generator
FERC	Federal Energy Regulatory Commission
FUCO	Foreign Utility Company
G&T Cooperative	Generation and Transmission Cooperative
GCIM	Gas Cost Incentive Mechanism
HHI	Herfindahl-Hirshman Index
I&M	Indiana Michigan Power Company, subsidiary of AEP
ICC	Illinois Commerce Commission
IMPA	Indiana Municipal Power Agency
IOU	Investor-Owned Utility
IPL	Indianapolis Power and Light
ISO	Independent System Operator
IURC or Commission	Indiana Utility Regulatory Commission
IWCR	IWC Resource Corporation
kWh	Kilowatt Hour
LDC	Local Distribution Company (gas)
MDPU	Massachusetts Department of Public Utilities
MPSC	Michigan Public Service Commission
NEES	New England Electric System
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NHPUC	New Hampshire Public Utility Commission
NIPSCO	Northern Indiana Public Service Company
OUCC	Office of the Utility Consumer Counselor
PPUC	Pennsylvania Public Utility Commission
PSI	PSI Energy
PUCO	Public Utility Commission of Ohio
PUHCA	Public Utility Holding Company Act 1935
PURPA	Public Utility Regulatory Policies Act 1978
PX	Power Exchange
REMC	Rural Electric Membership Cooperative
SEC	Securities and Exchange Commission
SIGECO	Southern Indiana Gas & Electric Company
SOLR	Supplier of Last Resort
T&D	Transmission and Distribution

X. GLOSSARY

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Aggregator: An entity that pools customers into a buying group for the purchase of a commodity good or service.

Alternative Regulatory Plan (ARP): In contrast to cost-of-service regulation, alternative regulatory plans are designed to allow the utility more flexibility in pricing energy to customers. ARPs may also contain provisions to streamline the regulatory approval process. Senate Enrolled Act 637 gave the IURC authority to consider ARPs.

Ancillary Services: Services that must be provided in the generation and delivery of electricity. As identified by the FERC, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and economic dispatch of plants); contractual arrangements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Back-up Service: A service designed to provide uninterrupted supply to the customer, thereby assuring reliability.

Broker: An agent for others in negotiating contracts, purchases or sales of electricity and associated services without owning any transmission or generation facilities. Unlike a marketer, a broker does not take title to the electricity being bought or sold.

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Cherry Picking: A term used to describe the action of an alternative power supplier coming into a market and selling power to the most attractive customers, usually large load industrial customers. Also called "cream skimming."

Citygate: A point of delivery to the gas local distribution company from the pipeline.

Code of Conduct: A set of rules issued by a regulatory authority that dictates how a utility and a marketing affiliate must transact business to ensure a level playing field for all market participants.

Competition Transition Charge (CTC): A non-bypassable charge applied to all customers designed to allow a utility to recover stranded costs.

Convergence Mergers: In the context of energy, mergers between gas and electric utilities.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Cost-of-Service: A term related to the current methods of regulating utilities (both gas and electric). A cost-of-service study analyzes a utility's average costs (also called embedded costs) of facilities and expenses in relationship to its revenues to determine rates (prices) for the customer. This is generally referred to as cost-of-service ratemaking or cost-of-service pricing.

Default Service: In a customer choice environment, default service refers to the service the customer would receive if the customer fails to select an alternative power supplier. In many cases this service would be provided by the incumbent utility.

Dekatherm (Dth): A unit of heating value equivalent to 1 million Btus.

Demand-Side Management (DSM): Conservation resource planning that considers factors affecting energy usage for each customer class; generally designed to reduce or shift load.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-use customer. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Earnings Test: An evaluation conducted as part of generating fuel cost adjustments and all gas cost adjustments to determine if the proposed change in fuel or gas costs would result in a utility earning in excess of its allowed net operating income. The actual evaluation is complex, but if the utility is found to be earning more than allowed, the excess revenue is returned to the ratepayers.

Electronic Bulletin Board: A location on the Internet where people send or retrieve messages and documents.

Exempt Wholesale Generators (EWG): Any person engaged in owning or operating eligible facilities and selling energy exclusively at wholesale.

Exit Fee: A type of recovery option for stranded costs. It applies to customers choosing an alternative power supplier prior to the end of a restructuring transition period.

Foreign Utility Company (FUCO): Any company that owns or operates facilities not located in the United States for generating, transmitting or distributing electricity for sale and deriving none of its income from utility operations conducted in the United States.

Gas Cost Adjustment (GCA): A formal and summary proceeding held quarterly or semi-annually by the IURC for natural gas utilities which allows these utilities to increase or decrease rates based on changes in the price of gas purchased from various sources. Rates are projected for three or six months into the future and "reconciled" from the past with costs from comparable time periods and an "earnings test" is part of the process.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Gigawatt (GW): A basic unit of measurement; 1 GW = 1,000 MW.

Gigawatt-Hour (GWh): One gigawatt of generation for one hour.

Green Power: Term used to described electricity produced from environmentally friendly or renewable resources, such as solar or wind power; see "Renewable Energy."

Herfindahl-Hirshman Index (HHI): A formula for defining market power by summing the squares of the individual market shares of all participants.

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any business.

Hydroelectric Power (hydro): A process of generating electricity by using the currents of a waterway. Usually a very low-cost method for producing power.

Independent System Operator (ISO): An independent organization or institution that would control the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Integrated Resource Planning (IRP): A strategy used by utilities and regulators to arrive at the least-cost mix of resources available to provide reliable electric or gas service.

Interstate Natural Gas Association of America (INGAA): An association of natural gas pipelines.

Kilowatt (kW): A basic unit of measurement; 1 kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Load Research: Primarily used by electric utilities to obtain hourly (or more often) usage data on residential customers, commercial establishments and industrial customers. This may also include data on the energy use of specific end-uses such as cooling, heating, cooking, and refrigeration. Due to the higher cost of meters, typically a representative sample is used so that inferences can be made to other customers with similar characteristics.

Local Distribution Company (LDC): The utility that is responsible for delivering gas to the customer behind the citygate (where the pipeline delivers gas to the LDC).

Marginal Cost: The change in total costs associated with a unit change in the quantity supplied; the cost of providing an additional Mcf or kWh.

Market Power: The extent to which a single firm can influence the market price of a good or service.

Mcf: One thousand cubic feet of natural gas, having the value of one million Btu.

Megawatt (MW): One thousand kilowatts or one million watts.

Megawatt-Hour (MWh): One megawatt of generation for one hour.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

North American Electric Reliability Council (NERC): A nonprofit organization formed for the purpose of coordinating electric system operation and planning throughout North America, including Mexico and Canada.

Pancaking: Occurs when a seller attempts to transmit electricity through the control areas of several utilities and must pay a separate transmission charge to each utility.

Power Exchange: An independent entity with no affiliate or financial interest in distribution, transmission or generation companies or facilities. It would match bids submitted by utilities, power marketers, brokers and other participants ranking the bids on a least-cost basis and arrange for the power to be delivered.

Power Marketers: A business entity engaged in buying and selling electricity, but does not own generation or transmission facilities. Power marketers take ownership of the electricity and offer risk management derivative products such as options, swaps, forward contracts and electricity futures.

Power Pool: Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs. Power pools that have operated under the current regulatory environment may eventually reorganize to form poolcos or ISOs in a customer choice environment.

Public Utility Holding Company Act of 1935 (PUHCA): A federal law that sought to correct abuses of utility holding companies. Holding companies largely confined to a single state are presumed to be susceptible to effective state regulation and are largely "exempt" from federal regulation under PUHCA. Multi-state holding companies must "register" with the SEC and comply with federal regulation under PUHCA.

Public Utility Regulatory Polices Act of 1978 (PURPA): A federal law that requires utilities to buy electric power from private "qualifying facilities" at an avoided cost rate. The avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase the power itself. Utilities must further provide customers who choose to generate their own electricity a reasonably priced back-up supply of electricity.

Qualifying Facility (QF): As defined in the Public Utility Regulatory Policies Act of 1978, a small power producer or cogenerator that can sell its electricity to public utilities at the utility's avoided cost.

Reciprocity: A provision of electric utility restructuring where utilities from outside a given state can only sell energy within the state if local utilities can, in turn, sell energy in the outside utilities' states.

Registered Holding Company: Any company that acquires more than 10 percent of the equity of a utility and as a consequence, must register with the Securities and Exchange Commission and is subject to all provisions of PUHCA.

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Renewable Energy (Green Power): Naturally replenishable energy resources; includes geothermal, biomass, hydro-electric, solar, tidal action and wind as means of electricity generation.

Rule 53: A Securities and Exchange Commission rule governing the aggregate investment by a registered holding company in Exempt Wholesale Generators and Foreign Utility Companies.

Safe Harbor: A financial or accounting step that avoids legal or tax consequences.

Securitization: A technique for financing assets in which the owner of a debt sells the right to receive debt payments. A bond is issued and the owner of the debt receives the cash proceeds from the bond. The bond is amortized and the bondholders are paid using the steady stream of revenue from the debt. In the electric industry restructuring debate, securitization is usually tied to stranded cost recovery.

Senate Enrolled Act 637: Codified as IC 8-1-2.5, this statute enables the IURC to consider alternative regulatory plans, among other things.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

Stranded Costs: Costs associated with assets that prove to be uneconomical in a competitive environment. Because these assets were previously approved by regulatory authorities and included in rates, utilities claim they should be able to fully recover these costs before the transition to customer choice is completed.

Supplier of Last Resort: In a customer choice market, the supplier of last resort will be a designated power supplier that will provide the energy needs of customer who can't or won't choose a supplier.

Thirty-Day Filings: Requests from utilities for approval of new rates, changes to nonrecurring charges, altered rules and regulations or changes in periodic trackers. This process is designed to allow these types of requests to be reviewed and approved by the Commission in a more expeditious and less costly manner than a formally docketed case.

Throughput (Gas): Actual or estimated volume of natural gas that may be carried on a pipeline over a period of time.

Transition Costs: Costs resulting from restructuring an industry from a regulatory environment to a competitive environment. Stranded costs are included in transition costs but may not be the only costs incurred.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Transportation (Gas): The transportation of natural gas by a pipeline (upstream of the citygate) and/or by the LDC (behind the citygate).

Unbundling: The process of separating out the package of services offered by an electric or gas company and charging separate rates for each service that fairly represents the cost of providing the service. In the electric industry, these may include: transmission, generation, distribution services, metering, billing, maintenance. In the natural gas industry, in addition to transportation of gas, unbundling may include storage, gathering, balancing services and other items.

Universal Service: A condition that makes a utility service (gas, electricity, telephone, etc.) available to any customer that wants it, at an affordable price.

Vertically Integrated Utilities (companies): An arrangement whereby the same company owns most or all of the facilities necessary for producing, transporting and selling electricity (or gas). Traditionally, vertically integrated electric utilities have owned the generation, transmission and distribution facilities. In some cases, electric utilities have also owned coal mines and gas supplies to increase the level of vertical integration.

XI. APPENDICES

Sales, Revenue and Market Share for Indiana Electric Utilities
1996 Summary

kWh

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Electric Utilities	20,617,747,000	16,387,182,000	35,467,894,000	394,651,000	72,867,474,000
Rural Electric Membership Corporations	4,384,104,330	1,761,192,149	—	57,491,613	6,202,788,092
Municipal Electric Utilities	1,663,430,657	3,574,823,826	—	78,265,281	5,316,519,764
Totals	**26,665,281,987**	**21,723,197,975**	**35,467,894,000**	**530,407,894**	**84,386,781,856**

Revenues

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Electric Utilities	$ 1,396,282,245	$ 977,844,154	$ 1,461,055,760	$ 41,248,460	$ 3,876,430,619
Rural Electric Membership Corporations	299,585,961	94,118,766	—	3,490,571	397,195,298
Municipal Electric Utilities	97,658,171	176,546,349	—	5,555,201	279,759,721
Totals	**$ 1,793,526,377**	**$ 1,248,509,269**	**$ 1,461,055,760**	**$ 50,294,232**	**$ 4,553,385,638**

Retail Market Share by kWh

Utility	Residential %	Commercial %	Industrial %	Other %	Total %
Investor Owned Electric Utilities	77.32	75.44	100.00	74.41	86.35
Rural Electric Membership Corporations	16.44	8.11	—	10.84	7.35
Municipal Electric Utilities	6.24	16.46	—	14.76	6.30

Retail Market Share by Revenues

Utility	Residential %	Commercial %	Industrial %	Other %	Total %
Investor Owned Electric Utilities	77.85	78.32	100.00	82.01	85.13
Rural Electric Membership Corporations	16.70	7.54	—	6.94	8.72
Municipal Electric Utilities	5.45	14.14	—	11.05	6.14

Investor-Owned Electric Utilities
1996 Data

kWh

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
1	Indiana Michigan Power Company	5,139,729,000	4,327,966,000	7,294,995,000	82,670,000	16,845,360,000
2	Indianapolis Power & Light Company	4,367,062,000	2,117,614,000	6,771,696,000	70,509,000	13,326,881,000
3	Northern Indiana Public Service Company	2,700,234,000	2,886,940,000	9,318,353,000	156,678,000	15,062,205,000
4	PSI Energy, Inc.	7,092,679,000	5,880,806,000	10,008,447,000	64,057,000	23,045,989,000
5	Southern Indiana Gas & Electric Company	1,318,043,000	1,173,856,000	2,074,403,000	20,737,000	4,587,039,000
	Totals	**20,617,747,000**	**16,387,182,000**	**35,467,894,000**	**394,651,000**	**72,867,474,000**

Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
1	Indiana Michigan Power Company	$ 343,768,334	$ 253,749,874	$ 312,777,071	$ 6,444,707	$ 916,739,986
2	Indianapolis Power & Light Company	261,819,276	131,464,648	298,719,364	9,043,130	701,046,418
3	Northern Indiana Public Service Company	269,906,153	247,807,691	428,272,692	15,742,946	961,729,482
4	PSI Energy, Inc.	431,519,385	280,245,562	347,923,907	7,941,359	1,067,630,213
5	Southern Indiana Gas & Electric Company	89,269,097	64,576,379	73,362,726	2,076,318	229,284,520
	Totals	**$ 1,396,282,245**	**$ 977,844,154**	**$ 1,461,055,760**	**$ 41,248,460**	**$ 3,876,430,619**

Average Rate Per kWh

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
1	Indiana Michigan Power Company	$ 0.07	$ 0.06	$ 0.04	$ 0.08	$ 0.05
2	Indianapolis Power & Light Company	0.06	0.06	0.04	0.13	0.05
3	Northern Indiana Public Service Company	0.10	0.09	0.05	0.10	0.06
4	PSI Energy, Inc.	0.06	0.05	0.03	0.12	0.05
5	Southern Indiana Gas & Electric Company	0.07	0.06	0.04	0.10	0.05

Retail Market Share

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	
1	Indiana Michigan Power Company	37.50%	27.68%	34.12%	0.70%	
2	Indianapolis Power & Light Company	37.35%	18.75%	42.61%	1.29%	
3	Northern Indiana Public Service Company	28.06%	25.77%	44.53%	1.64%	
4	PSI Energy, Inc.	40.42%	26.25%	32.59%	0.74%	
5	Southern Indiana Gas & Electric Company	38.93%	28.16%	32.00%	0.91%	

Rural Electric Membership Corporations
1996 Data

kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Bartholomew County R.E.M.C.	125,230,215	97,018,270	774,786	223,023,271
2.	Boone County R.E.M.C.	125,253,401	37,439,718	4,026,905	166,720,024
3.	Carroll County R.E.M.C.	80,759,817	50,170,248	-	130,930,065
4.	Central Indiana Power	118,120,010	17,599,595	169,360	135,888,965
5.	Decatur County R.E.M.C.	85,194,492	143,268,487	122,670	228,585,649
6.	Dubois R.E.C., Inc.	132,374,058	69,245,235	958,959	202,578,252
7.	Fulton County R.E.M.C.	60,392,527	12,049,345	3,007,584	75,449,456
8.	Harrison County R.E.M.C.	247,615,348	109,546,161	1,930,732	359,092,241
9.	Hendricks County R.E.M.C.	251,101,875	25,323,139	5,512,545	281,937,559
10.	Henry County R.E.M.C.	120,494,173	23,504,078	2,580,788	146,579,039
11.	Jackson County R.E.M.C.	297,887,243	57,874,917	56,199	355,818,359
12.	Jay County R.E.M.C.	78,217,204	15,597,961	-	93,815,165
13.	Johnson County R.E.M.C.	162,834,909	53,864,009	241,602	216,940,520
14.	Kankakee Valley R.E.M.C.	138,005,745	43,946,748	-	181,952,493
15.	Kosciusko County R.E.M.C.	148,432,220	95,718,173	738,175	244,888,568
16.	Marshall County R.E.M.C.	57,593,869	13,063,053	872,440	71,529,362
17.	Miami-Cass County R.E.M.C.	65,153,185	23,544,602	11,627,605	100,325,392
18.	Newton County R.E.M.C.	15,062,230	8,211,173	333,680	23,607,083
19.	Northeastern R.E.M.C.	227,216,913	168,836,886	639,620	396,693,419
20.	Orange County R.E.M.C.	74,444,724	10,238,162	921,294	85,604,180
21.	Parke County R.E.M.C	117,127,985	37,361,403	2,921,442	157,410,830
22.	Rush County R.E.M.C.	65,784,145	9,639,205	-	75,423,350
23.	Shelby County R.E.M.C.	105,962,033	35,881,411	13,919	141,857,363
24.	South Central Indiana R.E.M.C.	353,508,677	43,101,030	-	396,609,707
25.	Southeastern Indiana R.E.M.C.	288,686,688	49,823,086	-	338,509,774
26.	Southern Indiana R.E.C.	91,328,825	33,112,097	582,098	125,023,020
27.	Steuben County R.E.M.C.	61,718,754	34,583,192	717,821	97,019,767
28.	Tipmont R.E.M.C.	202,003,760	67,848,788	2,415,628	272,268,176
29.	United R.E.M.C.	143,531,579	247,850,998	-	391,382,577
30.	Utilities District of Western Indiana R.E.M.C.	199,870,831	40,861,061	15,316,284	256,048,176
31.	Wabash County R.E.M.C.	73,142,613	53,998,037	1,009,477	128,150,127
32.	White County R.E.M.C.	70,054,282	31,071,881	-	101,126,163
	Totals	**4,384,104,330**	**1,761,192,149**	**57,491,613**	**6,202,788,092**

Rural Electric Membership Corporations
1996 Data

Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Bartholomew County R.E.M.C.	$ 8,552,388	$ 4,593,767	$ 53,678	$ 13,199,833
2.	Boone County R.E.M.C.	8,143,920	1,976,286	231,223	10,351,429
3.	Carroll County R.E.M.C.	5,424,512	2,490,515	-	7,915,027
4.	Central Indiana Power	8,243,727	1,239,206	11,078	9,494,011
5.	Decatur County R.E.M.C.	5,581,895	5,985,966	9,926	11,577,787
6.	Dubois R.E.C., Inc.	8,215,691	3,740,126	64,430	12,020,247
7.	Fulton County R.E.M.C.	4,177,124	815,482	198,187	5,190,793
8.	Harrison County R.E.M.C.	15,591,048	5,129,240	140,691	20,860,979
9.	Hendricks County R.E.M.C.	17,266,538	2,001,910	421,921	19,690,369
10.	Henry County R.E.M.C.	6,791,524	1,449,500	187,557	8,428,581
11.	Jackson County R.E.M.C.	19,674,863	3,576,553	8,523	23,259,939
12.	Jay County R.E.M.C.	5,454,084	1,051,699	-	6,505,783
13.	Johnson County R.E.M.C.	11,921,412	3,124,615	42,077	15,088,104
14.	Kankakee Valley R.E.M.C.	10,253,247	3,031,087	-	13,284,334
15.	Kosciusko County R.E.M.C.	9,337,702	5,102,395	55,458	14,495,555
16.	Marshall County R.E.M.C.	5,105,287	972,458	95,058	6,172,803
17.	Miami-Cass County R.E.M.C.	4,471,372	1,359,095	408,606	6,239,073
18.	Newton County R.E.M.C.	1,127,487	539,600	22,564	1,689,651
19.	Northeastern R.E.M.C.	15,596,524	9,312,068	38,803	24,947,395
20.	Orange County R.E.M.C.	5,494,504	864,620	71,747	6,430,871
21.	Parke County R.E.M.C	8,856,444	2,275,379	281,926	11,413,749
22.	Rush County R.E.M.C.	4,735,670	648,649	-	5,384,319
23.	Shelby County R.E.M.C.	6,415,510	1,888,652	1,473	8,305,635
24.	South Central Indiana R.E.M.C.	25,323,533	2,058,287	-	27,381,820
25.	Southeastern Indiana R.E.M.C.	20,113,863	3,046,991	-	23,160,854
26.	Southern Indiana R.E.C.	6,316,554	1,826,773	44,030	8,187,357
27.	Steuben County R.E.M.C.	4,591,575	2,012,097	52,246	6,655,918
28.	Tipmont R.E.M.C.	14,275,894	4,430,759	178,005	18,884,658
29.	United R.E.M.C.	9,178,821	10,647,794	-	19,826,615
30.	Utilities District of Western Indiana R.E.M.C.	13,022,443	2,259,270	763,153	16,044,866
31.	Wabash County R.E.M.C.	5,041,638	2,896,680	108,211	8,046,529
32.	White County R.E.M.C.	5,289,167	1,771,247	-	7,060,414
	Totals	**$ 299,585,961**	**$ 94,118,766**	**$ 3,490,571**	**$ 397,195,298**

Rural Electric Membership Corporations
1996 Data
Average Rate Per kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Bartholomew County R.E.M.C.	$0.0683	$0.0473	$0.0693	$0.0592
2.	Boone County R.E.M.C.	0.0650	0.0528	0.0574	0.0621
3.	Carroll County R.E.M.C.	0.0672	0.0496	-	0.0605
4.	Central Indiana Power	0.0698	0.0704	0.0654	0.0699
5.	Decatur County R.E.M.C.	0.0655	0.0418	0.0809	0.0506
6.	Dubois R.E.C., Inc.	0.0621	0.0540	0.0672	0.0593
7.	Fulton County R.E.M.C.	0.0692	0.0677	0.0659	0.0688
8.	Harrison County R.E.M.C.	0.0630	0.0468	0.0729	0.0581
9.	Hendricks County R.E.M.C.	0.0688	0.0791	0.0765	0.0698
10.	Henry County R.E.M.C.	0.0564	0.0617	0.0727	0.0575
11.	Jackson County R.E.M.C.	0.0660	0.0618	0.1517	0.0654
12.	Jay County R.E.M.C.	0.0697	0.0674	-	0.0693
13.	Johnson County R.E.M.C.	0.0732	0.0580	0.1742	0.0695
14.	Kankakee Valley R.E.M.C.	0.0743	0.0690	-	0.0730
15.	Kosciusko County R.E.M.C.	0.0629	0.0533	0.0751	0.0592
16.	Marshall County R.E.M.C.	0.0886	0.0744	0.1090	0.0863
17.	Miami-Cass County R.E.M.C.	0.0686	0.0577	0.0351	0.0622
18.	Newton County R.E.M.C.	0.0749	0.0657	0.0676	0.0716
19.	Northeastern R.E.M.C.	0.0686	0.0552	0.0607	0.0629
20.	Orange County R.E.M.C.	0.0738	0.0845	0.0779	0.0751
21.	Parke County R.E.M.C	0.0756	0.0609	0.0965	0.0725
22.	Rush County R.E.M.C.	0.0720	0.0673	-	0.0714
23.	Shelby County R.E.M.C.	0.0605	0.0526	0.1058	0.0585
24.	South Central Indiana R.E.M.C.	0.0716	0.0478	-	0.0690
25.	Southeastern Indiana R.E.M.C.	0.0697	0.0612	-	0.0684
26.	Southern Indiana R.E.C.	0.0692	0.0552	0.0756	0.0655
27.	Steuben County R.E.M.C.	0.0744	0.0582	0.0728	0.0686
28.	Tipmont R.E.M.C.	0.0707	0.0653	0.0737	0.0694
29.	United R.E.M.C.	0.0639	0.0430	-	0.0507
30.	Utilities District of Western Indiana R.E.M.C.	0.0652	0.0553	0.0498	0.0627
31.	Wabash County R.E.M.C.	0.0689	0.0536	0.1072	0.0628
32.	White County R.E.M.C.	0.0755	0.0570	-	0.0698

Rural Electric Membership Corporations
1996 Data

Retail Market Share

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER
1.	Bartholomew County R.E.M.C.	64.79%	34.80%	0.41%
2.	Boone County R.E.M.C.	78.67%	19.09%	2.23%
3.	Carroll County R.E.M.C.	68.53%	31.47%	-
4.	Central Indiana Power	86.83%	13.05%	0.12%
5.	Decatur County R.E.M.C.	48.21%	51.70%	0.09%
6.	Dubois R.E.C., Inc.	68.35%	31.12%	0.54%
7.	Fulton County R.E.M.C.	80.47%	15.71%	3.82%
8.	Harrison County R.E.M.C.	74.74%	24.59%	0.67%
9.	Hendricks County R.E.M.C.	87.69%	10.17%	2.14%
10.	Henry County R.E.M.C.	80.58%	17.20%	2.23%
11.	Jackson County R.E.M.C.	84.59%	15.38%	0.04%
12.	Jay County R.E.M.C.	83.83%	16.17%	-
13.	Johnson County R.E.M.C.	79.01%	20.71%	0.28%
14.	Kankakee Valley R.E.M.C.	77.18%	22.82%	0.00%
15.	Kosciusko County R.E.M.C.	64.42%	35.20%	0.38%
16.	Marshall County R.E.M.C.	82.71%	15.75%	1.54%
17.	Miami-Cass County R.E.M.C.	71.67%	21.78%	6.55%
18.	Newton County R.E.M.C.	66.73%	31.94%	1.34%
19.	Northeastern R.E.M.C.	62.52%	37.33%	0.16%
20.	Orange County R.E.M.C.	85.44%	13.44%	1.12%
21.	Parke County R.E.M.C	77.59%	19.94%	2.47%
22.	Rush County R.E.M.C.	87.95%	12.05%	-
23.	Shelby County R.E.M.C.	77.24%	22.74%	0.02%
24.	South Central Indiana R.E.M.C.	92.48%	7.52%	-
25.	Southeastern Indiana R.E.M.C.	86.84%	13.16%	-
26.	Southern Indiana R.E.C.	77.15%	22.31%	0.54%
27.	Steuben County R.E.M.C.	68.98%	30.23%	0.78%
28.	Tipmont R.E.M.C.	75.60%	23.46%	0.94%
29.	United R.E.M.C.	46.30%	53.70%	-
30.	Utilities District of Western Indiana R.E.M.C.	81.16%	14.08%	4.76%
31.	Wabash County R.E.M.C.	62.66%	36.00%	1.34%
32.	White County R.E.M.C.	74.91%	25.09%	-

Municipal Electric Utilities
1996 Data

kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1	Anderson Municipal Light & Power	302,503,789	376,428,080	4,900,099	683,831,968
2	Auburn Municipal Electric	45,263,668	421,459,125	N/A	466,722,793
3	Bargersville Municipal Power & Light	N/A	N/A	N/A	N/A
4	Bluffton Municipal Electric	41,173,774	131,311,180	4,441,037	176,925,991
5	Boonville Municipal Light & Power	31,010,956	35,315,736	N/A	66,326,692
6	Cannelton Municipal Electric	6,510,669	11,005,948	411,720	17,928,337
7	Centerville Municipal Power & Light	16,016,542	5,901,198	1,414,124	23,331,864
8	Columbia City Municipal Electric	32,555,293	67,607,221	1,428,224	101,590,738
9	Covington Municipal Electric	12,295,337	10,406,428	N/A	22,701,765
10	Crawfordsville Municipal Electric Light & Power	71,373,246	306,096,205	2,395,474	379,864,925
11	Edinburgh Municipal Electric	21,090,393	43,948,307	N/A	65,038,700
12	Ferdinand Municipal Light Plant	5,826,997	25,251,175	N/A	31,078,172
13	Flora Municipal Electric	10,686,814	9,433,107	525,395	20,645,316
14	Frankfort City Light & Power	67,375,116	267,949,610	2,640,839	337,965,565
15	Greenfield Municipal Electric	47,172,458	140,089,506	2,582,279	189,844,243
16	Kingsford Heights Municipal Electric	3,224,342	1,044,707	462,512	4,731,561
17	Knightstown Municipal Electric	12,393,919	8,502,987	627,436	21,524,342
18	Lawrenceburg Municipal Electric	24,866,385	55,629,293	977,509	81,473,187
19	Lebanon Municipal Electric	59,222,848	80,954,432	2,904,339	143,081,619
20	Logansport Municipal Electric	88,077,973	236,720,779	2,638,150	327,436,902
21	Mishawaka Municipal Electric	158,911,218	319,321,884	21,101,076	499,334,178
22	New Ross Municipal Electric	2,069,727	329,705	132,034	2,531,466
23	Peru Municipal Electric Light & Power	84,672,242	121,751,881	5,340,693	211,764,816
24	Richmond Municipal Power & Light	190,403,685	669,581,426	10,937,572	870,922,683
25	Scottsburg Municipal Electric	184,320,000	N/A	N/A	184,320,000
26	South Whitley Municipal Electric	7,969,318	11,054,052	1,015,056	20,038,426
27	Straughn Municipal Electric	1,153,345	157,851	30,034	1,341,230
28	Tell City Municipal Electric	32,158,264	61,422,298	1,089,223	94,669,785
29	Tipton Municipal Electric	35,097,374	61,022,759	1,059,947	97,180,080
30	Troy Municipal Electric	4,009,352	6,441,844	44,261	10,495,457
31	Washington City Municipal Light & Power	64,025,613	88,685,102	9,166,248	161,876,963
	Totals	**1,663,430,657**	**3,574,823,826**	**78,265,281**	**5,316,519,764**

N/A = Not available

Municipal Electric Utilities
1996 Data

Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1	Anderson Municipal Light & Power	$17,702,980	$18,819,678	$303,803	$36,826,461
2	Auburn Municipal Electric	2,042,230	18,470,629	114,985	20,627,844
3	Bargersville Municipal Power & Light	1,485,296	1,120,173	103,839	2,709,308
4	Bluffton Municipal Electric	2,258,558	6,206,315	244,318	8,709,191
5	Boonville Municipal Light & Power	2,142,354	2,139,627	60,042	4,342,023
6	Cannelton Municipal Electric	499,179	800,551	18,111	1,317,841
7	Centerville Municipal Power & Light	678,827	423,908	67,115	1,169,850
8	Columbia City Municipal Electric	1,910,175	3,754,669	92,971	5,757,815
9	Covington Municipal Electric	765,586	656,358	4,000	1,425,944
10	Crawfordsville Municipal Electric Light & Power	4,613,224	13,798,082	193,390	18,604,696
11	Edinburgh Municipal Electric	1,153,205	3,191,000	41,733	4,385,938
12	Ferdinand Municipal Light Plant	402,939	1,530,633	13,078	1,946,650
13	Flora Municipal Electric	601,815	531,214	29,587	1,162,616
14	Frankfort City Light & Power	3,990,757	11,262,453	219,870	15,473,080
15	Greenfield Municipal Electric	2,675,770	6,183,692	235,399	9,094,861
16	Kingsford Heights Municipal Electric	252,273	81,738	36,187	370,198
17	Knightstown Municipal Electric	687,697	479,468	22,391	1,189,556
18	Lawrenceburg Municipal Electric	1,331,863	2,959,038	30,478	4,321,379
19	Lebanon Municipal Electric	3,254,940	4,449,327	159,625	7,863,892
20	Logansport Municipal Electric	5,940,274	12,879,651	134,528	18,954,453
21	Mishawaka Municipal Electric	9,999,071	17,893,877	1,493,330	29,386,278
22	New Ross Municipal Electric	177,528	28,280	11,325	217,133
23	Peru Municipal Electric Light & Power	4,809,646	5,418,019	248,488	10,476,153
24	Richmond Municipal Power & Light	11,373,665	31,784,339	996,860	44,154,864
25	Scottsburg Municipal Electric	8,430,327	N/A	N/A	8,430,327
26	South Whitley Municipal Electric	456,432	633,106	58,136	1,147,674
27	Straughn Municipal Electric	72,963	9,986	1,900	84,849
28	Tell City Municipal Electric	2,186,351	3,648,275	80,551	5,915,177
29	Tipton Municipal Electric	1,973,414	2,967,231	70,962	5,011,607
30	Troy Municipal Electric	271,750	436,622	3,000	711,372
31	Washington City Municipal Light & Power	3,517,082	3,988,410	465,199	7,970,691
	Totals	**$97,658,171**	**$176,546,349**	**$5,555,201**	**$279,759,721**

N/A = Not available

Municipal Electric Utilities
1996 Data

Average Rate Per kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1	Anderson Municipal Light & Power	$ 0.0585	$ 0.0500	$ 0.0620	$ 0.0539
2	Auburn Municipal Electric	0.0451	0.0438	-	0.0442
3	Bargersville Municipal Power & Light	-	-	-	-
4	Bluffton Municipal Electric	0.0549	0.0473	0.0550	0.0492
5	Boonville Municipal Light & Power	0.0691	0.0606	-	0.0655
6	Cannelton Municipal Electric	0.0767	0.0727	0.0440	0.0735
7	Centerville Municipal Power & Light	0.0424	0.0718	0.0475	0.0501
8	Columbia City Municipal Electric	0.0587	0.0555	0.0651	0.0567
9	Covington Municipal Electric	0.0623	0.0631	-	0.0628
10	Crawfordsville Municipal Electric Light & Power	0.0646	0.0451	0.0807	0.0490
11	Edinburgh Municipal Electric	0.0547	0.0726	-	0.0674
12	Ferdinand Municipal Light Plant	0.0692	0.0606	-	0.0626
13	Flora Municipal Electric	0.0563	0.0563	0.0563	0.0563
14	Frankfort City Light & Power	0.0592	0.0420	0.0833	0.0458
15	Greenfield Municipal Electric	0.0567	0.0441	0.0912	0.0479
16	Kingsford Heights Municipal Electric	0.0782	0.0782	0.0782	0.0782
17	Knightstown Municipal Electric	0.0555	0.0564	0.0357	0.0553
18	Lawrenceburg Municipal Electric	0.0536	0.0532	0.0312	0.0530
19	Lebanon Municipal Electric	0.0550	0.0550	0.0550	0.0550
20	Logansport Municipal Electric	0.0674	0.0544	0.0510	0.0579
21	Mishawaka Municipal Electric	0.0629	0.0560	0.0708	0.0589
22	New Ross Municipal Electric	0.0858	0.0858	0.0858	0.0858
23	Peru Municipal Electric Light & Power	0.0568	0.0445	0.0465	0.0495
24	Richmond Municipal Power & Light	0.0597	0.0475	0.0911	0.0507
25	Scottsburg Municipal Electric	0.0457	-	-	0.0457
26	South Whitley Municipal Electric	0.0573	0.0573	0.0573	0.0573
27	Straughn Municipal Electric	0.0633	0.0633	0.0633	0.0633
28	Tell City Municipal Electric	0.0680	0.0594	0.0740	0.0625
29	Tipton Municipal Electric	0.0562	0.0486	0.0669	0.0516
30	Troy Municipal Electric	0.0678	0.0678	0.0678	0.0678
31	Washington City Municipal Light & Power	0.0549	0.0450	0.0508	0.0492

Municipal Electric Utilities
1996 Data
Retail Market Share

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER
1	Anderson Municipal Light & Power	48.07%	51.10%	0.82%
2	Auburn Municipal Electric	9.90%	89.54%	0.56%
3	Bargersville Municipal Power & Light	54.82%	41.35%	3.83%
4	Bluffton Municipal Electric	25.93%	71.26%	2.81%
5	Boonville Municipal Light & Power	49.34%	49.28%	1.38%
6	Cannelton Municipal Electric	37.88%	60.75%	1.37%
7	Centerville Municipal Power & Light	58.03%	36.24%	5.74%
8	Columbia City Municipal Electric	33.18%	65.21%	1.61%
9	Covington Municipal Electric	53.69%	46.03%	0.28%
10	Crawfordsville Municipal Electric Light & Power	24.80%	74.16%	1.04%
11	Edinburgh Municipal Electric	26.29%	72.76%	0.95%
12	Ferdinand Municipal Light Plant	20.70%	78.63%	0.67%
13	Flora Municipal Electric	51.76%	45.69%	2.54%
14	Frankfort City Light & Power	25.79%	72.79%	1.42%
15	Greenfield Municipal Electric	29.42%	67.99%	2.59%
16	Kingsford Heights Municipal Electric	68.15%	22.08%	9.78%
17	Knightstown Municipal Electric	57.81%	40.31%	1.88%
18	Lawrenceburg Municipal Electric	30.82%	68.47%	0.71%
19	Lebanon Municipal Electric	41.39%	56.58%	2.03%
20	Logansport Municipal Electric	31.34%	67.95%	0.71%
21	Mishawaka Municipal Electric	34.03%	60.89%	5.08%
22	New Ross Municipal Electric	81.76%	13.02%	5.22%
23	Peru Municipal Electric Light & Power	45.91%	51.72%	2.37%
24	Richmond Municipal Power & Light	25.76%	71.98%	2.26%
25	Scottsburg Municipal Electric	-	-	-
26	South Whitley Municipal Electric	39.77%	55.16%	5.07%
27	Straughn Municipal Electric	85.99%	11.77%	2.24%
28	Tell City Municipal Electric	36.96%	61.68%	1.36%
29	Tipton Municipal Electric	39.38%	59.21%	1.42%
30	Troy Municipal Electric	38.20%	61.38%	0.42%
31	Washington City Municipal Light & Power	44.13%	50.04%	5.84%

ANALYSIS OF GAS SALES DATA

CITIZENS GAS AND COKE UTILITY

	1996	1995	1994	1993	1992	1991	1990	1989	1988	1987
Total Sales By Class (Dth)										
Residential	28,483,330	25,157,784	25,786,208	26,338,840	24,288,992	24,139,468	23,270,985	25,551,980	24,904,564	22,837,225
Commercial	17,041,493	12,349,373	11,653,505	13,161,441	12,958,457	11,199,869	12,006,600	12,693,703	11,602,486	10,099,903
Industrial	8,313,991	2,359,386	2,054,039	4,550,216	5,784,674	2,055,701	3,096,836	3,307,359	2,648,699	2,350,672
Other	3,029,750	15,268,936	3,825,713	-	-	-	-	-	-	-
Total	56,868,564	55,135,479	43,319,465	44,050,497	43,032,123	37,395,038	38,374,421	41,553,042	39,155,749	35,287,800
Total Transportation By Class (Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	929,276	4,011,118	3,967,667	2,854,679	1,528,888	2,921,525	1,532,351	2,076,425	2,243,491	2,140,729
Industrial	5,084,490	9,543,189	9,086,966	6,407,740	4,246,554	7,351,172	6,119,584	6,371,800	6,761,870	6,314,468
Other	163,656	-	-	-	-	-	-	-	-	-
Total	6,177,422	13,554,307	13,054,633	9,262,419	5,775,442	10,272,697	7,651,935	8,448,225	9,005,361	8,455,197
Total Throughput By Class (Dth)										
Residential	28,483,330	25,157,784	25,786,208	26,338,840	24,288,992	24,139,468	23,270,985	25,551,980	24,904,564	22,837,225
Commercial	17,970,769	16,360,491	15,621,172	16,016,120	14,487,345	14,121,394	13,538,951	14,770,128	13,845,977	12,240,632
Industrial	13,398,481	11,902,575	11,141,005	10,957,956	10,031,228	9,406,873	9,216,420	9,679,159	9,410,569	8,665,140
Other	3,193,406	15,268,936	3,825,713	-	-	-	-	-	-	-
Total	63,045,986	68,689,786	56,374,098	53,312,916	48,807,565	47,667,735	46,026,356	50,001,267	48,161,110	43,742,997
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	5.17%	24.52%	25.40%	17.82%	10.55%	20.69%	11.32%	14.06%	16.20%	17.49%
Industrial	37.95%	80.18%	81.56%	58.48%	42.33%	78.15%	66.40%	65.83%	71.85%	72.87%
Other	5.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	9.80%	19.73%	23.16%	17.37%	11.83%	21.55%	16.63%	16.90%	18.70%	19.33%

ANALYSIS OF GAS SALES DATA

INDIANA GAS COMPANY, INC.

	1996	1995	1994	1993	1992	1991	1990	1989	1988	1987
Total Sales By Class (Dth)										
Residential	50,507,000	40,592,000	46,634,000	44,690,000	41,065,000	38,996,000	36,194,000	35,976,000	34,173,000	31,329,000
Commercial	20,178,000	16,195,000	18,258,000	17,613,000	15,711,000	15,225,000	13,960,000	13,707,000	12,916,000	13,790,000
Industrial	21,892,000	19,409,000	21,268,000	36,744,000	31,771,000	24,928,000	19,038,000	13,695,000	13,254,000	9,702,000
Other	-	-	-	-	-	-	-	-	-	-
Total	92,577,000	76,196,000	86,160,000	99,047,000	88,547,000	79,149,000	69,192,000	63,378,000	60,343,000	54,821,000
Total Transportation By Class (Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	-	-	-	-	-	-	-	-	-	-
Industrial	34,165,000	33,312,000	30,125,000	12,307,000	13,438,000	18,354,000	21,027,000	23,427,000	22,000,000	21,712,000
Other	-	-	-	-	-	-	-	-	-	-
Total	34,165,000	33,312,000	30,125,000	12,307,000	13,438,000	18,354,000	21,027,000	23,427,000	22,000,000	21,712,000
Total Throughput By Class (Dth)										
Residential	50,507,000	40,592,000	46,634,000	44,690,000	41,065,000	38,996,000	36,194,000	35,976,000	34,173,000	31,329,000
Commercial	20,178,000	16,195,000	18,258,000	17,613,000	15,711,000	15,225,000	13,960,000	13,707,000	12,916,000	13,790,000
Industrial	56,057,000	52,721,000	51,393,000	49,051,000	45,209,000	43,282,000	40,065,000	37,122,000	35,254,000	31,414,000
Other	-	-	-	-	-	-	-	-	-	-
Total	126,742,000	109,508,000	116,285,000	111,354,000	101,985,000	97,503,000	90,219,000	86,805,000	82,343,000	76,533,000
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Industrial	60.95%	63.19%	58.62%	25.09%	29.72%	42.41%	52.48%	63.11%	62.40%	69.12%
Other	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	26.96%	30.42%	25.91%	11.05%	13.18%	18.82%	23.31%	26.99%	26.72%	28.37%

ANALYSIS OF GAS SALES DATA

NORTHERN INDIANA PUBLIC SERVICE COMPANY

	1996	1995	1994	1993	1992	1991	1990	1989	1988	1987
Total Sales By Class (Dth)										
Residential	77,050,000	71,113,000	67,665,000	70,707,000	67,742,000	64,159,000	61,484,000	65,586,000	69,179,000	61,017,000
Commercial	29,401,000	26,908,000	25,994,000	27,466,000	26,191,000	24,051,000	24,286,000	26,446,000	26,777,000	23,122,000
Industrial	16,528,000	15,178,000	14,638,000	13,567,000	15,278,000	18,907,000	21,273,000	27,310,000	31,241,000	47,193,000
Other	7,922,000	941,000	357,000	450,000	493,000	484,000	470,000	551,000	654,000	665,000
Total	130,901,000	114,140,000	108,654,000	112,190,000	109,704,000	107,601,000	107,513,000	119,893,000	127,851,000	131,997,000
Total Transportation By Class (Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	3,740,000	3,855,000	4,330,000	-	-	-	-	-	-	-
Industrial	151,446,000	157,849,000	160,232,000	162,853,000	147,818,000	135,921,000	133,950,000	126,013,000	123,796,000	92,630,000
Other	-	-	-	-	-	-	-	-	-	-
Total	155,186,000	161,704,000	164,562,000	162,853,000	147,818,000	135,921,000	133,950,000	126,013,000	123,796,000	92,630,000
Total Throughput By Class (Dth)										
Residential	77,050,000	71,113,000	67,665,000	70,707,000	67,742,000	64,159,000	61,484,000	69,586,000	69,179,000	61,017,000
Commercial	33,141,000	30,763,000	30,324,000	27,466,000	26,191,000	24,051,000	24,286,000	26,446,000	26,777,000	23,122,000
Industrial	167,974,000	173,027,000	174,870,000	176,420,000	163,096,000	154,828,000	155,223,000	153,323,000	155,037,000	139,823,000
Other	7,922,000	941,000	357,000	450,000	493,000	484,000	470,000	551,000	654,000	665,000
Total	286,087,000	275,844,000	273,216,000	275,043,000	257,522,000	243,522,000	241,463,000	249,906,000	251,647,000	224,627,000
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	11.29%	12.53%	14.28%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Industrial	90.16%	91.23%	91.63%	92.31%	90.63%	87.79%	86.30%	82.19%	79.85%	66.25%
Other	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	54.24%	58.62%	60.23%	59.21%	57.40%	55.81%	55.47%	50.42%	49.19%	41.24%

ANALYSIS OF GAS SALES DATA

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

	1996	1995	1994	1993	1992	1991	1990	1989	1988	1987
Total Sales By Class (Dth)										
Residential	10,435,599	8,947,330	9,419,367	9,880,924	8,774,852	8,746,747	8,502,944	8,869,774	8,772,000	6,311,424
Commercial	5,174,821	4,240,884	4,177,139	4,389,045	3,986,459	3,867,513	3,696,761	3,815,649	3,722,000	2,604,555
Industrial	2,667,594	1,810,903	1,628,831	2,402,969	3,170,595	2,504,050	2,139,499	1,989,033	2,128,000	1,510,401
Other	985,306	387,167	165,229	150,332	20,736	21,578	22,633	27,824	30,000	10,705
Total	19,263,320	15,386,284	15,390,566	16,823,270	15,952,642	15,139,888	14,361,837	14,702,280	14,652,000	10,437,085
Total Transportation By Class (Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	268,144	277,923	293,439	238,154	89,482	190,602	231,680	Information not available		
Industrial	11,049,737	10,964,904	10,946,277	10,938,554	9,229,065	9,115,763	9,851,104	Information not available		
Other	483,495	720,704	344,822	193,834	184,608	178,900	193,579	Information not available		
Total	11,801,376	11,963,531	11,584,538	11,370,542	9,503,155	9,485,265	10,276,363	10,443,052	9,754,000	8,842,251
Total Throughput By Class (Dth)										
Residential	10,435,599	8,947,330	9,419,367	9,880,924	8,774,852	8,746,747	8,502,944	8,869,774	8,772,000	6,311,424
Commercial	5,442,965	4,518,807	4,470,578	4,627,199	4,075,941	4,058,115	3,928,441	Information not available		
Industrial	13,717,331	12,775,807	12,575,108	13,341,523	12,399,660	11,619,813	11,990,603	Information not available		
Other	1,468,801	1,107,871	510,051	344,166	205,344	200,478	216,212	Information not available		
Total	31,064,696	27,349,815	26,975,104	28,193,812	25,455,797	24,625,153	24,638,200	25,145,332	24,406,000	19,279,336
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	4.93%	6.15%	6.56%	5.15%	2.20%	4.70%	5.90%	Information not available		
Industrial	80.55%	85.83%	87.05%	81.99%	74.43%	78.45%	82.16%	Information not available		
Other	32.92%	65.05%	67.61%	56.32%	89.90%	89.24%	89.53%	Information not available		
Total	37.99%	43.74%	42.95%	40.33%	37.33%	38.52%	41.71%	41.53%	39.97%	45.86%

ANALYSIS OF GAS SALES DATA

CITIZENS GAS, INDIANA GAS, NIPSCO AND SIGECO COMBINED

	1996	1995	1994	1993	1992	1991	1990	1989	1988	1987
Total Sales By Class (1,000 Dth)										
Residential	166,476	145,810	149,505	151,617	141,871	136,041	129,452	135,984	137,029	121,495
Commercial	71,795	59,693	60,083	62,629	58,847	54,343	53,949	56,662	55,017	49,616
Industrial	49,402	38,757	39,589	57,264	56,004	48,395	45,547	46,301	49,272	60,756
Other	11,937	16,597	4,348	600	514	506	493	579	684	676
Total	299,610	260,858	253,524	272,111	257,236	239,285	229,441	239,526	242,002	232,543
Total Transportation By Class (1,000 Dth)										
Residential	-	-	-	-	-	-	-	-	-	-
Commercial	4,937	8,144	8,591	3,093	1,618	3,112	1,764	Information not available		
Industrial	201,745	211,669	210,390	192,506	174,732	170,742	170,948	Information not available		
Other	647	721	345	194	185	179	194	Information not available		
Total	207,330	220,534	219,326	195,793	176,535	174,033	172,905	168,331	164,555	131,639
Total Throughput By Class (1,000 Dth)										
Residential	166,476	145,810	149,505	151,617	141,871	136,041	129,452	135,984	137,029	121,495
Commercial	76,733	67,837	68,674	65,722	60,465	57,456	55,713	Information not available		
Industrial	251,147	250,426	249,979	249,770	230,736	219,137	216,495	Information not available		
Other	12,584	17,318	4,693	794	698	684	686	Information not available		
Total	506,940	481,392	472,850	467,904	433,770	413,318	402,347	411,858	406,557	364,182
Percent Transportation to Throughput										
Residential	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commercial	6.43%	12.01%	12.51%	4.71%	2.68%	5.42%	3.17%	Information not available		
Industrial	80.33%	84.52%	84.16%	77.07%	75.73%	77.92%	78.96%	Information not available		
Other	5.14%	4.16%	7.35%	24.41%	26.44%	26.14%	28.21%	Information not available		
Total	40.90%	45.81%	46.38%	41.84%	40.70%	42.11%	42.97%	40.87%	40.48%	36.15%

1997 RESTRUCTURING ACTIVITIES BY STATE

Alabama

In 1996 the Alabama Senate approved a bill (H.B. 350) that gave Alabama state authorities power to review new power contracts signed by customers who leave their utility system and order payment of stranded costs. The bill gives the Alabama Public Service Commission power to review contracts signed by Alabama Power customers with new suppliers and order stranded cost recovery where appropriate. The bill gave special powers to state courts to carry out the same review functions for public power utilities. This bill is designed to sunset when a more comprehensive retail competition law is adopted by the legislature.

Alaska

Due to its geographical location, the Alaska Commission was not contacted.

Arizona

New rules opening the state to competition in the electric utility industry over a four-year period beginning in 1999 were adopted December 23, 1996 by the Arizona Corporation Commission.

Under the new rules utilities will be required to file proposals for unbundled services by December 21, 1997 (Docket No. U-000 94165). They have to separately offer such services as generation, transmission and distribution of electricity, meter reading, billing and collection and consumer information services at rates to be approved by the commission.

Retail customers will be able to select "standard offer" services which is the traditional electric service customers now receive, or they may choose competitive services. Companies will have to file tariffs describing their services and their maximum rates for commission approval. They can charge lower rates as long as those rates cover costs.

Principal milestones include:

Beginning January 1, 1999, utilities will have to make 20% of their peak 1995 demand available to all customers. No more than half the amount may be sold to large customers.

Beginning January 1, 2001, utilities will have to make 50% of their peak 1995 demand available in the competitive market. Of that total, 30% will be reserved for residential customers.

Beginning January 1, 2003, 100% of the total electric supply will be available for competitive market.

Beginning January 1, 1999, at least one-half of 1% of power sold competitively must come from a photovoltaic or solar thermal source. That percentage increases to 1% after December 31, 2001.

All electric companies will be required to obtain commission approval to provide competitive service. Municipalities and political subdivisions such as Salt River Project could voluntarily open their markets to competition on the same terms and conditions. In return this creates for them an opportunity to compete elsewhere in the state.

In March 1997, Arizona Public Service and Tucson Electric Power, the state's largest investor-owned utilities, filed appeals asking the Maricopa County Superior Court to order the Arizona Corporation Commission to revise and expand the new rules it adopted for phasing in deregulation. APS claimed (Docket No. CV97-03753) that "formalized hearings, legislative action, state and local tax implications and legal issues need to be addressed along with several other key issues." TEP claimed (Docket No. CV97-03748) "...the rules as adopted raise more questions than answers and do not address many serious issues that are detrimental to the rights of our customers and the investment of our shareholders."

Arkansas

The Arkansas legislature adopted a resolution ordering its joint Insurance and Commerce Committee to review electric industry competition issues by the end of 1998. The resolution (SCR24) requires the committee to study whether to give customers access to competitive power supplies and to set a timetable for a transition to such a system. The committee must report its findings to the next regular session of the legislature, which meets at the beginning of 1999.

California

A coalition of energy service providers, marketers and customer groups is negotiating with California's three largest electric utilities and lobbying the California Public Utilities Commission to adopt a single statewide tariff for direct-access customers. The Direct Access Alliance filed its proposal for a uniform direct-access tariff with the PUC as an alternative to the utilities' tariff proposals. The proposed tariff define rules for how customers will obtain direct access and fees utilities

can charge for providing direct-access. All three utilities have proposed different rules and protocols for marketers and energy service providers to follow in switching customers to direct access from utility service beginning January 1, 1998.

Along with their lack of uniform service charges, the alliance criticized the utility tariff proposals for seeking to impose service charges on customers and service providers without the cost being reviewed by the PUC. Finally the alliance questioned the utilities imposing requirements on service providers while exempting themselves from the same requirements.

The PUC incorporated the alliance's proposal in a report issued August 22, 1997. A proposed decision on direct-access rules and tariffs is expected October 9, 1997.

July 25, 1997, the California Senate approved the first of two bills paving the way for the state's three electric investor-owned utilities to issue $7-billion to $9-billion of rate-reduction bonds. On September 3, 1997 the California Public Utilities Commission approved $7.3-billion in rate reduction bonds to finance a 10% electric rate cut for residential and small business customers beginning January 1, 1998.

The rate-reduction bonds were authorized by the electric restructuring legislation enacted by the California legislature last year to finance a mandatory 10% rate cut for residential and small commercial customers beginning next year.

Colorado

Colorado's legislature adjourned for 1997 without passing two measures intended to initiate restructuring of the state's electric industry. A wide-ranging measure, HB 1277 by Rep. Paul Schauer died without a vote in the House Public Affairs and Labor Committee which Schauer chairs.

The Senate approved but the House Appropriations Committee killed, SB 147 by Sen. Dave Wattenberg proposing appointment of a legislative interim committee to study deregulation of the electric utility industry.

Connecticut

The Connecticut legislature abandoned attempts to adopt an electric industry restructuring law in 1997 after key lawmakers said they feared that the proposed bill would not produce the promised 10% savings for ratepayers. (House Bill 6774) Backers of the legislation plan to reintroduce the bill next year when the session begins in February 1998.

Delaware

The Public Service Commission opened a proceeding on July 15, 1997 that will culminate in a January 1998 report to the House of Representatives on restructuring of the electric utility industry in Delaware.

The Commission was urged in House Resolution No. 36 to provide a report that would include recommendations and possible alternative approaches to restructuring that state's electric industry.

The Commission staff submitted a draft report August 8, 1997. Public hearings will be held in each of the state's three counties. A copy of the staff's draft report can be found on the PSC's web site at http://www.state.de.us/govern/agencies/pubservc/psc.htm.

Florida

On January 8, 1997 the Public Service Commission established an inter-divisional electric industry work group to "expand and enhance the PSC staff's knowledge and understanding of issues affecting electric utilities and electric customers resulting from the increasing competitive pressures in the markets for electricity." A formal proceeding has not been established.

March 18, 1997, the House Utilities and Telecommunications Committee established a research group to monitor industry restructuring developments.

No restructuring activity is expected by either the PSC or the Legislature during 1997.

Georgia

In April 1997, the staff of the Georgia Public Service Commission began conducting a series of informal workshops with electric utilities, public advocacy groups, commercial and industrial customers and Georgia homeowners to develop and explore the range of issues to be confronted during the transition to a competitive electric environment. The workshops will examine restructuring efforts taking place throughout the nation, the impact of competition on the consumer as well as environmental issues and energy efficiency programs. When the workshops conclude in the summer of 1997, staff will present the Commission with their findings and the positions of interested parties.

Hawaii

Due to its geographical location, the Hawaii Commission was not contacted.

Idaho

The Idaho Public Utilities Commission, in accordance with House Bill 399 passed by the Idaho Legislature earlier in 1997, will begin the process of restructuring Idaho's electric industry with public presentations beginning August 6, 1997.

House Bill 399 directs the Commission to begin an analysis of the effects electric restructuring could have on Idaho residents. Determining costs incurred by electric suppliers providing generation, transmission and distribution services is "essential to that analysis," the Commission decided.

In accordance with H399, the Commission will schedule proceedings with each electric utility with more than 1,000 customers - including cooperatives and municipal electric suppliers historically exempted from state regulation.

Governor Phil Batt recently suggested to the Commission that utilities' investments in "public purposes" (renewable resources and low-income assistance programs) should be a separate cost component along with generation, transmission and distribution. Batt further urged the Commission to separate various public purpose programs, particularly universal service and fish mitigation costs, for possible listing as separate line items.

April 1997 the Idaho Public Utilities Commission approved a two-year pilot program that will enable some of Washington Water Power Company's residential and commercial customers to purchase energy from alternative suppliers. Approximately 1,900 WWP customers from Washington and 900 Idaho customers will be selected at random to participate in the program which will begin July 1, 1997 and end June 30, 1999.

Illinois

August 18, 1997, the Illinois Commerce Commission released their report severely criticizing Senate Bill 55 - the major legislative initiative aimed at bringing customer choice to the state.

While SB 55 establishes a five-year timetable for offering access to alternative suppliers, "the length of the stranded-cost recovery period, the inadequacy of stranded-cost verification, and other anti-competitive provisions of the bill will render the freedom to choose an illusion for the great majority of Illinois citizens," the ICC declares.

"The balance struck by SB 55 leans too heavily in favor of the utilities," the commission added. The bill gives a competitive edge to electric utilities at the expense of alternative retail power suppliers. Customers of alternative power suppliers will be required to pay a fixed delivery charge, a fixed transition charge and a fixed decommissioning charge, in addition to the price of energy, a utility's customers could receive a discount on all on those items. As a result of this pricing flexibility, utilities could prevent competitors from entering the market. The ICC also criticized SB 55's failure to unbundle power supply rates from delivery service rates for utility customers, thus restricting a consumer's ability to compare the prices of service offerings of competing suppliers.

Indiana

September 9, 10, and 23, and again on October 14, 1997 the Regulatory Flexibility Committee of the Indiana legislature held hearings on electric utility restructuring. The speakers at the hearing provided information on a variety of restructuring issues and described the status of restructuring activities in other states. The next hearing is scheduled for November 4 and 5, 1997.

Iowa

MidAmerican Energy proposed a retail wheeling pilot program for Iowa commercial and industrial customers, as it agreed to do in the settlement with industrials, the Iowa Office of Consumer Advocate and other utilities that set a 7.6% rate cut by June 1998.

The proposal was filed at the IUB September 5, 1997 and at the FERC September 9, 1997.

Sixty MW are to be offered under the Market Access Service pilot during the first year, with 15 MW to be added each year until the pilot ends - either January 1, 2005 or when customer choice becomes available.

The pilot would be offered in two phases. During the first 24 months, participating customers could take between 4 MW and 10 MW at any single site. In Phase 2, the minimum would be cut to 2 MW for a single site and customers could participate with aggregated loads at multiple site, provided they are under common ownership and have a minimum total load of 4 MW.

Customers would buy transmission under MidAmerican's open-access tariff with amendments to accommodate retail access. Distribution service would be provided under the rates in the pilot's price schedule. MidAmerican will hold a lottery if interest in the pilot exceeds the limits.

Customers could return to bundled service at bundled rates if the utility can acquire capacity and energy at or below the bundled prices. The customer would have to pay any cost above the bundled price.

Suppliers wishing to participate in the pilot must be members of NERC regional reliability council. Suppliers must also provider similar reciprocal pilot program arrangements to MidAmerican. MidAmercian plans to participate in its pilot program as a power supplier.

February 10, 1997 the Iowa Utilities Board released a report stating that there was no compelling reason for Iowa officials to move quickly to restructure the electric utilities in the state. The IUB will continue to monitor restructuring activites because of the potential for federal legislation mandating some type of retail access and competition.

Kansas

The Kansas Task Force on Retail Wheeling has set July 1, 2001 as deadline for electric deregulation in the state. The task force is preparing legislation to be presented to the 1998 session of the Kansas legislature, which begin in January.

The task force set the deadline after receiving a study of issues related to retail competition, prepared by the National Regulatory Research Institute. The study stated that the major investor-own utilities in Kansas (Western Resources and Kansas City Power & Light) have no stranded costs. When the companies' merger is completed, they will own 94% of the 1,200-MW Wolf Creek nuclear plant. Western has estimated that Wolf Creek represents $1.2-billion in stranded assets. But the NRRI study says that ,while Wolf Creek has high fixed costs due to the large initial investment, variable costs are very low. Other highly efficient fossil fuel plants owned by the two utilities more than off-set any stranded costs associated with Wolf Creek. The study argues that no stranded cost provisions will be needed for Western/KCPL.

A representative from Western Resources criticized the NRRI study saying that the study showed that operating income would rise by 20-million dollars while rates declined and that cash flows were higher than the book value of the business.

The NRRI study also took issue with an earlier study prepared for the Kansas cooperatives painting a gloomy picture for those entities. The NRRI study says Kansas co-op rates are 30% higher than the weighted average for co-op rates in six surrounding states and 28% above the national average. Kansas generation and transmission co-ops are charging all-requirements member systems 376% to 500% more than they charge other wholesale customers.

The task force report has three more major steps before it is introduced as legislation: three days of hearings in September, four days of public input hearings in October and a bill markup session November 12-13.

A recent study, "The Impacts of Retail Wheeling on Municipal Utilities in Kansas" concluded that "Because municipal electric utilities are so intertwined with the provision of many local public services, any price changes for electric service will have non-price effects revealed through higher taxes, reduction in general city services and the loss of local control over electric service."

The study was conducted by the Kansas Public Finance Center of the Hugo Wall School of Urban and Public Affairs at Wichita State University on behalf of Kansas Municipal Utilities and the Kansas Municipal Energy Agency. Additional information on the study is available by calling (316) 978-6332 or at Internet address http://www.twsu.edu/~kpfcwww/ .

Kentucky

Union Light, Heat & Power, a unit of Cinergy, has asked the Kentucky Public Service Commission to scrap its formal integrated resource plan filing requirement, saying traditional utility planning "has been left behind" as the electric industry moves to competition.

At the time Kentucky's IRP rule was implemented, the regulatory focus was to insure that a utility's investments within its system were planned in a prudent manner. Competition was not a serious consideration at the time. All that has changed. Even in traditionally low-cost states, such as Kentucky, customer choice is being considered.

ULH&P offers several reasons why prudent planning is not a critical concern; first, the utilities monopoly on generation is ending and new entrants to the market will change the power pricing structure. Second, in anticipation of retail competition, utilities will tend to defer decisions to build in favor of power purchases to minimize potential stranded costs. Third, the emergence of a liquid electricity market will provide new opportunities to obtain power and to manage risk.

Finally, ULH&P stated it believed it was unfair for a state utility commission to require electric companies to file IRPs filled with information about pricing and costs, bulk power purchases, load forecasts and average customer usage. Potentially supplying this type of information to competitors who may not be subject to IRP rules places ULH&P at a competitive disadvantage.

The PSC is expected to make a decision on ULH&P's petition by late September of early October 1997.

In December, 1996 the Public Service Commission initiated a series of informal, one-to-one, fact finding conferences with utilities and consumer groups to discuss the issues and concerns surrounding electric restructuring. This was not a formal docketed proceeding. These conferences were expected to conclude in June 1997.

Louisiana

September 17, 1997, Entergy New Orleans filed a plan with the New Orleans City Council calling for a six-year transition period before retail choice is implemented. Entergy said its plan would cap rates at current levels during the six years, insuring rates would not rise, but also leaving the city council free to lower rates during the period if needed.

At the same time, the plan would speed amortization of costs for Entergy New Orleans' share of the Grand Gulf nuclear plant so that the company's stranded cost would be eliminated by the end of the period. Outside analysts have placed the company's stranded-cost exposure as high as $692-million, one of the highest stranded-cost-t-equity ratios of any utility in the country.

Entergy's plan also calls for unbundling rates and including a universal service charge to cover nuclear plant costs. The universal charge would be applied to customers that drop Entergy's supplies during the transition period but remain connected to the grid.

It is expected that the plan will be opposed by industrial customers who want a quick transition to retail choice and oppose stranded-investment recovery.

The city council is currently investigating competition issues and gave Entergy New Orleans permission to propose a transition plan.

In June, 1997 negotiations between Entergy and customer groups on restructuring issues failed. Similar to the New Orleans proposal, Entergy wanted to delay full retail choice until 2004 and be allowed to speed up depreciation of nuclear assets and collect stranded-cost charges from departing customers during that period. Industrial customers wanted to begin customer choice in 1999 and require Entergy to assume half of the stranded-cost burden. Competition issues will be addressed by the Louisiana Public Service Commission in the coming months.

Maine

A joint committee of the Maine Legislature unanimously approved an electric restructuring bill (LD 1804) May 14, 1997 that orders full retail choice to begin in March 2000 and requires utilities to divest generation assets by that time.

House Bill 1804 also contains a provision that will allow the state's largest investor-owned utilities to market some energy in their own distribution territories.

Under a compromise with customer groups, the utility marketers will be allowed to win no more that one-third share of the affiliated market. This guarantees that outside marketers will get at least two-thirds share, plus the right to compete for the whole market.

In a second major action, the committee decided that all power sellers would have to have at least a 30% renewables content in their power sold in the state.

The bill also gives the PUC wide discretion in several areas, including setting up new statewide conservation programs and deciding whether rural cooperatives and municipals should be subject to deregulation.

The legislation does not contain any provision for securitizing stranded costs. This issue may be revisited in the future.

Maryland

The Maryland Public Service Commission said it will reconsider retail competition after rejecting such a change two years ago. It is responding to a staff report that says conditions have changed and that competition now offers benefits to the states' ratepayers. (Case No.8738)

The staff report noted that federal deregulation initiatives have created a vibrant wholesale market that could be tapped for end-users. In addition, new technologies allow generation to be developed cheaply and quickly. At the same time, surrounding states, such as New Jersey and Pennsylvania, are already moving ahead on retail competition.

The staff recommended that the PSC begin a prototype competition program in April 1999 involving 10% of all customers and expand this to 20% in April 2000. Retail choice would open to all remaining users by April 2001. Customers could choose to continue regulated service and they should not be made worse off.

The staff recommends that prudently-incurred identifiable and unmitigated stranded costs should be recoverable by the utilities. Alternatively, ratepayers should have the opportunity to benefit from all assets acquired under regulation. The PSC will conduct hearings in the case August 18-22, 1997.

Massachusetts

September 18, 1997, the Massachusetts Supreme Judicial Court recognized the rights of utilities to collect stranded costs in a decision involving the Massachusetts Institute of Technology and Commonwealth Energy subsidiary of Cambridge Electric (Case No. SJC-07277).

The Cambridge/MIT dispute marked the first major clash over stranded costs in the state, and was being watched as a landmark for how the courts are likely to treat stranded costs. The court ruled that the Massachusetts Department of Public Utilities acted within its jurisdiction when it issued a decision on the amount of stranded costs MIT should pay for departing from Cambridge Electric's system. The courts also sent back to the DPU to review how it had originally decided that MIT should pay only 75% of the stranded cost.

July 9, 1997 Boston Edison finalized a restructuring settlement agreement with the state attorney general and the Division of Energy Resources. The agreement parallels restructuring deals reached by New England Electric System and Eastern Utilities. The agreement must now be reviewed by the state Department of Public Utilities.

February, 1997, The Massachusetts Department of Public Utilities approved New England Electric System's restructuring settlement agreement. The agreement will allow NEES to sell off about 4,000 MW in fossil fuel and hydroelectric generation. NEES subsidiary Massachusetts Electric will become a distribution company and will recover stranded costs through a 2.8 cents/kWh wires charge. Mass. Electric will continue to offer power for seven years through a standard offer at a 10% rate reduction. NEES plan had widespread support, with more than 14 groups signing on to it including independent power producers and environmentalists.

Michigan

The Michigan Public Service Commission on June 5, 1997 approved a state restructuring plan that opens Michigan's electric industry to competition. By 2002, all customers in the state will be allowed to choose their power supplier.

July 1, 1997 a large group of stakeholders in electric utility restructuring proposed an alternative deregulation plan and asked state legislators for consideration during the summer recess.

July 14, 1997, Detroit Edison announced it would conduct a contested case proceeding to consider tariff terms for customers seeking independent suppliers instead of following the deregulation framework established by the PSC.

July 21, 1997, In an effort to link stranded-cost recovery to market price of power, Consumers Energy announced it would auction off the rights to portions of its Michigan-based, non-utility generating capacity each year from 1998 until 2007. The winning bidder will obtain the rights to the electricity produced by these qualified facilities and the sale will establish a market price against which stranded costs can be measured.

August 1997, Michigan Attorney General Frank Kelley, the Residential Ratepayer Consortium and the Assn. Of Business Advocating Tariff Equity - an industrial organization - have petitioned the Ingham County Circuit Court to order the Public Service Commission to stop deregulation proceedings until the PSC determines it has the authority to order retail wheeling.

Minnesota

During 1996 a work group created by the Minnesota Public Utilities Commission examined ways to bring wholesale competition to the state and to consider other near-term actions aimed at developing a more competitive electric industry in Minnesota. On October 18, 1996 the PUC's Electric Competition Work Group (ECWG) issued its report concerning the establishment of robust wholesale competition in Minnesota, including participation in the Midwest Area Power Pool and the implementation of an independently operated regional transmission system. Definite timelines for industry restructuring

have not yet been established. The ECWG may issue another report in late 6/97 that is expected to identify retail competition issues, but not make recommendations.

During the 1997 legislative session, Senate File 1820 was enacted that establishes a task force to study electric industry restructuring. The task force is to issue a report to the Legislature by January 15, 1998.

Mississippi

The PSC began an inquiry into competition issues in August 1996 and held hearings in April, 1997.

In an order issued July 1, 1997 (Docket 96-UA-389) the Mississippi Public Service Commission asked the state Public Utility Staff to draw up a restructuring plan for the state by November, 1997 but it did not say when it wanted retail choice to begin. Once it receives the plan, the PSC will hold hearings and then make recommendations later next year for either new legislation or other actions.

The PSC action signals that the state legislature will not take up deregulation until 1999 at the earliest. But it is also possible consumer groups may try to get the legislature to act in 1998 without waiting for a final PSC recommendation.

March 1997, HB 1130 signed, authorizes PSC to consider alternate methods of regulation for electricity and gas.

Missouri

Union Electric unveiled details of its 100-MW Experimental Retail Wheeling Pilot project. The two-year pilot, required as part of the Missouri Public Service Commission's approval of UE's planned merger with CIPSCO to form Ameren, will involve all classes of customers except street lighting.

The pilot involves two distinct models: Power Exchange, under which UE serves as the sole aggregator for participating customers and solicits bids from energy suppliers to serve those customers, and Direct Access, under which selected energy suppliers negotiate directly with pilot participants and enter into power-supply contracts with UE on the participants' behalf.

A total of 5,200 customers are expected to take part in the pilot. The company said it would make special effort to recruit low-income volunteers in both areas of the pilot.

Residential and small commercial volunteers must participate for a minimum of three months. If a participant leaves, he cannot rejoin the program.

The PSC must review and approve the pilot plan before it can be implemented (Case No. EO-98-95). The 24-month test period begins on the first day electricity is delivered under the pilot.

April, 1997, The Missouri Public Service Commission opened a docket and established a task force to examine retail electric competition based on developments at the federal level (EW-97-245).

Montana

The Montana Senate passed Senate Bill 390 in April 1997 to restructure the state's electric utility industry, and allowing customer choice of suppliers as soon as July 1, 1998 and setting an across-the-board rate freeze beginning July 1, 1998.

Under the bill, large industrial customers can begin exercising choice of supplier on July 1, 1998. After pilot programs on choice, all residential, commercial and smaller industrial customers will have choice of supplier no later than July 1, 2002.

The two year rate freeze begins July 1, 1998 with an additional two-year freeze on the energy component of bills for residential and commercial customers.

The procedure for recovery of stranded costs includes a utility's submission of its proposed stranded costs to the Public Service Commission, the commission's review of those costs, the utility's efforts to mitigate costs and PSC's subsequent ruling on the level of recoverable stranded costs.

Nebraska

This unusual state with a unicameral legislature and 100% public power has begun a three-year legislative study of the state's electric power industry. The goal is to examine moves towards competition in the industry nationwide and develop alternatives to enhance the ability of Nebraska's public power industry to thrive in a competitive environment. Phase I of the study, to be completed by the end of 1997, will be an examination of the structure of the power industry in the state and issues facing the state's electric utilities. Phase II will be an in-depth analysis of issues related to competition and of possible

policy changes to strengthen public power's position in the future. This phase will begin July 1, 1997 and be completed by the end of 1999.

Nevada

On April 15, 1997 Assembly Bill 366, which was supported by most of the members of the PSC, was introduced by the Government Affairs Committee. The bill, which would grant the PSC authority over certain electric utility restructuring issues, calls for the PSC to establish a timetable by January 1, 1999 for the implementation of customer choice. The bill was adopted by the legislature and Governor Bob Miller is expected to sign it.

Prior to opening the markets, the commission must conduct rulemakings to unbundle rates, identify stranded costs, establish licensing procedures for new market entrants, designate which services are potentially competitive and create consumer protections and labeling.

The bill requires that noncompetitive transmission and distribution facilities be open on an equitable basis to alternative sellers and their customers.

Incumbent utilities seeking to provide competitive services will be required to do so through and affiliate.

Included in the bill are provisions for a provider-of-last-resort mechanism so that those areas which are not able or choose not to receive services from and alternative supplier will continue to be assured safe, reliable, and economic electric service.

The bill sets a multi-year residential rate cap unless an electric utility can make a convincing showing that additional revenues are necessary.

The legislation also restructures the Nevada PSC into a three-member Public Utilities Commission and one three-member Transportation Services Authority Agency, dividing the utility and transportation responsibilities of the agency.

A renewable energy provision in the bill is expected to phase in a requirement that 1% of all electricity consumed annually be produced by Nevada renewable energy producers.

New Hampshire

The state of New Hampshire and Public Service New Hampshire ended their mediation efforts September 2, 1997 without reaching agreement on key restructuring issues.

The failure means the two sides will now return to a federal district court to litigate a controversial state restructuring plan, issued February 1997 that allow PSNH only 60% stranded-cost recovery.

The prospect of continued court action makes it unlikely that the state can implement retail choice as planned on January 1, 1998 and may even miss the July 1, 1998 deadline set under the state restructuring law passed in May 1996.

It is also increasingly likely that the legal battle over the New Hampshire plan may result in court rulings on restructuring issues that will have national implication.

New Hampshire is the only state so far where a final deregulation plan is being challenged by a utility in court and PSNH has raised several constitutional questions about New Hampshire's rights to impose a new regulatory system and stranded-cost recovery scheme which have not been tested up to now.

The city of Dover, N.H. has issued a request for letters of interest from private groups willing to partner with it to set up a municipal utility and end reliance on high-cost power supplies from Public Service New Hampshire. Formal proposals are to submitted by October 24, 1997.

The state of New Hampshire changed its law earlier this year to make it easier for cities to set up municipal utilities. Dover, is now likely to become a test case for municipalization in the state.

While the city would probably experience greater saving if the state begins full retail choice, it is possible that choice will be delayed beyond 1998 by the current dispute over stranded cost between the state and PSNH.

New Jersey

The New Jersey Board of Public Utilities accelerated the move to full competition in its final restructuring order. It also wants new suppliers to disclose their portfolios and emissions (Docket No. EX94120585Y). The final plan begins the

restructuring process in October 1998 with 10 % of users. This expands to 20% in January 1999, 35% in April 1999 50% in October 1999, 75% in April 2000 and to all remaining ratepayers in July 2000.

The board's findings and recommendations will be submitted to the state legislature, which must amend various statutes. While the lawmakers are not bound by the proposals, the plan is backed by Governor Christine Todd Williams and the BPU hopes for a comprehensive bill that will essentially put the plan into effect.

July 15, 1997, New Jersey utilities filed restructuring plans. The utilities estimated a total stranded cost of $8.6-billion, including $5.5-billion for Public Service Electric & Gas, $1.8-billion for GPU Energy and $1.3-billion for Atlantic Energy.

The plans were required by the Board of Public Utilities which wants to phase in retail competition from October 1998 to April 2000. GPU and AE filed plans conforming to that schedule but PSE&G proposed letting all customers shop for energy at the start of 1999. They would also be able to purchase capacity from outside suppliers as soon as capacity trading is established in the PJM Interconnection.

Other issues addressed in the restructuring filings include: "securitization" of generating costs to allow refinancing at lower interest rates, "non-utility generation transition charge", procedures for phasing-in customer choice and environmental concerns.

New Mexico

September, 1997, the collaborative efforts by utilities and other interested parties to draft a plan for introducing choice for New Mexico electric customers by 2001 have collapsed. The talks ended in impasse because Public Service New Mexico could not agree to the demand of some participants for significantly larger rate reduction than PNM offered. Also neither PNM nor the other utilities could accept forced divestiture of their distribution system for any reason, even in exchange for stranded-asset recovery.

Alternatively, PNM has prepared a proposal "representing principles that a cross-section of collaborative participants can endorse." Some of the major elements of PNM's proposal are:

- Opening the New Mexico electric business to full retail competition in January 2001.

Reducing rates by $10-million a year for residential customers from the date legislation is approved through the date of open access, and freezing electric rates for all other customers at their current level until 2001.

Accepting the risk of stranded-cost recovery on purchased power, all fossil fuel generation and other generation excluded from current jurisdictional rates.

Establishing a holding company with separate subsidiaries formed for each of PNM's business lines to protect customers against market power and cross-subsidization.

Establishing an Independent System Operator governed by an independent board to oversee state or regional transmission.

PNM's proposal has been submitted to the Public Utility Commission and to the state legislative committee now studying electric industry restructuring.

New York

The New York Public Service Commission has finalized the restructuring plan for Consolidated Edison, opening retail competition for all of its 3 million customers by the end of 2001 (Case No. 96-E-0897). This is the first competition plan approved by the PSC.

Under the plan, Con Ed will start the transition process by opening competition for a 500-MW block in June 1998, including 300 MW for large commercial and industrial users, and 200 MW for residential and small commercial ratepayers. It will open additional 1,000-MW blocks in April 1999 and April 2000. By the end of 2001 all customers will be able to seek outside suppliers. Full competition could come earlier if the New York Power Pool quickly establishes an independent system operator. The restructuring plan allows all customers to choose suppliers 18 months after the ISO is in place or by 2001, whatever comes first.

Under the restructuring plan, small users will get an initial rate reduction of 3.3% that will increase to 10% by the end of the fifth year. More rate reductions could follow if the company receives good offers when it auctions generating plants.

The timing of the auction of the company's New Yorks City generating plants was also accelerated in the PSC's ruling. In addition the final plan requires that only 70% of New Yorks city load must be served by in-city generation down from 80% in the earlier settlement.

The PSC did not estimate stranded investment at the September 10 meeting though the issue will be addressed in the formal written order. The final stranded cost number will be largely determined by the power plant auction and could be reduced by securitization.

The New York Commission is still considering restructuring plans filed earlier by the following utilities:

Central Hudson Gas & Electric - The ALJ on this case has recommended rejecting the plan (Opinion No. 96-12)

New York State Electric & Gas - A restructuring settlement was filed and now must be reviewed by intervenors and the ALJ. A final ruling is expected in October, 1997.

Orange & Rockland Utilities - ALJ recommended that the plan be rejected. A final ruling is expected in September 1997.

Rochester Gas & Electric - Restructuring plan filed in April 1997 was approved by the assigned ALJ on July 16, 1997.

North Carolina

Two municipal power agencies in North Carolina, with estimated stranded costs totaling $6-billion, have proposed that all customers in the state uniformly share the cost of paying down that debt. The statewide group proposed to the North Carolina Utilities Commission and state legislators that stranded costs from all utilities, both IOUs and munis, be spread among all ratepayers in the state and be recovered through a per-kWh fee on all retail customers.

The debate about electric-industry restructuring and deregulation in North Carolina is expected to intensify this fall as a new 23-member study commission holds its first meeting. The panel, whose creation was supported by utilities, electric cooperatives and customer groups, has been charged by the state legislature with preparing an interim report on restructuring and deregulation for the legislature by January 1998 and a final report by January 1999.

North Dakota

February, 1997, the North Dakota Public Service Commission adopted NARUC principles which will be used as a guide for the possible restructuring of the electric industry. The general principles emphasize that changes in the industry should occur only when they meet two goals - improved economic efficiency and serving the broader public interest. The Commission will use the principles to review pending federal legislation and determine how proposed laws will affect North Dakota consumers. The Commission will also use the principles as it looks at restructuring issues within the state.

Ohio

Two of Ohio's highest-cost electric companies have threatened to sue the state for damages if a competition plan under consideration by the General Assembly's Joint Committee on Electric Utility Deregulation does not provide for stranded cost recovery.

The 12-member joint committee is working toward an October 1, 1997 deadline to prepare a proposal to submit to the General Assembly, probably in early 1998. For several weeks the committee has heard testimony from groups that would be affected by the deregulation.

In a related development, Centerior and Ohio Edison were joined by American Electric Power, Cinergy and Dayton Power & Light in urging the state Public Utility Commission not to release company-specific stranded-cost figures to the legislative panel. The utilities argued that the commission's notion of preparing stranded-cost estimates for the committee is fraught with problems and is not an effective use of time or resources and could well be inconsistent with the policy ultimately established by the General Assembly.

In response, PUC chairman Craig Glazer said the commission will give legislators a range for stranded costs but no specific numbers for individual utilities.

Oklahoma

April 23, 1997, Oklahoma lawmakers gave final approval to Senate Bill 500 - the Oklahoma Electric Restructuring Act of 1997. The bill was sent to Governor Frank King, who is expected to sign it promptly. The bill, which mandates a series of studies leading to retail competition by July 1, 2000.

The bill will not be the legislature's final action on restructuring. Recommendations from the studies by the Oklahoma Corporation Commission, on a wide variety of technical and financial issues, and the Oklahoma Tax Commission, on utility policies, will require legislative approval before taking effect.

Oregon

Portland General Electric filed a pilot plan with the Oregon Public Utility Commission calling for full retail choice for all customers beginning as early as October 1998. The plan would require all existing utilities in Oregon to deregulate their systems if they sought to compete in PGE's territory. PGE would get out of the energy sales business and operate its transmission and distribution system as a regulated entity. Competitors would offer energy sales, energy services and metering and billing.

Generation assets would be transferred to a non-regulated entity and might be offer for sale. PGE also seeks to recover 100% of its stranded costs over an unspecified period.

A 3% "systems benefit charge" to fund investments in energy conservation, renewable energy and low-income assistance is also part of the proposal.

PGE will bid out to energy service providers the opportunity to provide "universal service." That provider will serve as supplier of last resort for PGE customers who choose not to participate in open retail access or do not receive service from the providers they do choose. PGE believes that it need OPUC approval, but not legislation, to implement this plan.

Pennsylvania

August 27, 1997, PECO Energy reached a restructuring settlement with major intervenor groups, avoiding a fight at the Pennsylvania Public Utility Commission and ending litigation on stranded costs.

The settlement, which must be approved by the PUC, calls for 10% rate cuts, full retail competition by 2000 and a $2-billion write-off of stranded costs. Under the settlement, PECO would allow two-thirds of customers to choose other suppliers at the start of 1999 and would open the market to all others a year later.

PECO also agreed to write-off $2-billion in stranded costs. Under the settlement, the company would be allowed to recover $5.461-billion and would be allowed to "securitize" up to $4-billion of its costs using special "transition bonds" established in the competition law.

The third major piece of the settlement involves rate reductions of 10%, which would begin in September 1998, and be guaranteed through the end of 2000. In addition, there will be an 18% reduction in the "competition transition charge" (CTC) used to collect stranded costs - from 2001 through 2008, which will act as a cap on stranded cost recovery. After 2008, the CTC expires and rates would revert to market levels.

Finally, other provisions of the settlement include; caps on transmission and distribution rates until 2004, three years longer than provided for in the Electric Competition Act, and an increase in the Customer Assistance Program for low-income users from the present 40,000 customers to 100,000.

Alleghney Power and DQE unit of Duquesne Light have filed restructuring plans with the Pennsylvania Public Utility Commission and they expect stranded costs to reach as high as $3.4-billion.

Allegheny projects that its Pennsylvania stranded costs will run about $2-billion, including $1.1-billion related to its generating plants; $730-million from contracts with non-utility generators; $110-million in regulatory assets and $60-million in transition costs.

The company will recover stranded costs through a "competitive transition charge" (CTC) passed along to all customers and it estimates that the CTC will amount to about 1.7 cents/kWh in the first year of competition.

Duquesne Light did not submit a formal stranded-cost estimate because it plans to allow market forces to determine the level of stranded costs. However, the company did estimate a range from $850-million to $1.4-billion in stranded costs for the first year of competition.

Earlier this year Pennsylvania Power & Light filed its restructuring plans with the PPUC estimating $4.6-billion in stranded costs.

Rhode Island

Most Rhode Island manufacturers opted to stay with utilities when retail choice began July 1, 1997 because they wrongly feared that leaving would lock them out of future standard-offer rates, according to an advocacy group for large electricity users.

Retail choice is now available for about 30 manufacturing firms in the state with an annual average demand of 1,500 kW. But so far, only one manufacturer has confirmed plans to buy from a competitive supplier.

According to The Energy Council of Rhode Island, others declined because they believe that they would not be able to return to the utilities and take advantage of standard-offer rates, which are expected to range from 2.8 cents/kWh to 3.2 cents/kWh beginning next year. The companies are now buying power through interim unbundled rates.

Recently utilities sent out letters to customers saying they can buy from a competitive supplier now and still be eligible for standard-offer rates as long as they notify the utility 30 days before the standard offer becomes available. It is expected that the standard-offer rates will be announced in the next two months and will begin in January 1998.

South Carolina

Piedmont Municipal Power Agency, which arranges power for 10 distribution municipal utilities in South Carolina, told an August 19, 1997 hearing on deregulation at the South Carolina Commission that due to its then-appropriate purchase of a 25% stake in a Duke nuclear plant, that its stranded costs may approach $1-billion. If this amount must were to be recovered from the agency's customers, the recovery charge would be approximately 6 to 7 cents/kWh, collected over a ten-year period.

Instead, PMPA proposed that the estimated $3-billion plus stranded costs of all utilities in South Carolina be aggregated and recovered by a uniform, non-bypassable charge of less than 1 cent/kWh for 10 years. PMPA claims that all the state's electric customers have benefited from the completion and operation of the station and the rescue of Duke from financial difficulties.

At the request of the state legislature, the PSC plans to develop an electric-industry restructuring proposal by January 31, 1998. The legislature is expected to act on the matter during its 1998 session.

South Dakota

As of October 1995, the South Dakota Public Utilities Commission was not investigating retail wheeling or restructuring.

According to the NRRI Box Score sheet, South Dakota has a discussion forum addressing electric utility restructuring.

Tennessee

Rep. Zack Wamp (R-Tenn.) Chairman of the Tennessee Valley Caucus, took a tough stance June 5, 1997 against a proposal from fellow caucus member Rep. Bob Clement (D-Tenn.) To form a commission to examine how to deal with the Tennessee Valley Authority when Congress takes up electricity restructuring legislation.

Wamp testified that Congress, and not an independent commission, represents the purest approach to solving TVA's problems.

Texas

Texas-New Mexico Power has returned to the Texas Public Utility Commission with a transition-to-competition plan but this time there is the added pressure of a rate review requested by eight of the cities the company serves. The company failed to gain consensus on a previous plan and therefore submitted the new combination transition and rate filing.

The new plan, submitted July 31, 1997, includes a 6% rate cut for residential customers and a 3% rate cut for commercial customers, implemented in phases over a five-year transition period beginning in 1998. It holds industrial rates unchanged. At the end of the transition period, which would be used to reduce the company's estimated $270-million in stranded costs, customers would be free to choose their electricity suppliers.

The only other company to present a transition-to-competition plan to the PUC so far is Entergy Gulf States. But the Texas commission has indicated that they intend for all of the state's IOUs to either submit rate or transition filings or reach settlement with interested parties on the same over the next 18 months.

Utah

On March 14, 1997 the Governor singed H.B.313 that provides for an interim rate freeze on electric service rates and creates the Electric Deregulation and Customer Choice Task Force. The bill specifies the Task Force's goals and objectives and requires that it submit a report by November 1997.

Vermont

Vermont utilities failed an attempt to win approval for a state securitization plan to help them buy down costly power-purchase contracts.

Green Mountain Power and Central Vermont Public Service floated a Grantor Trust plan in April 1997 under which the state would have issued low-cost bonds backed by charges to power customers to provide buy-down funds.

Key legislators announced in mid-May that they opposed any action on the trust plan this year. Instead, they want to consider such securitization concepts as part of a comprehensive package of restructuring measures in 1998.

Virginia

November 12 ,1996 the State Corporation Commission (SCC) directed its public utilities staff and the three largest electric companies in Virginia to provide additional information relevant to potential changes and the possible emergence of competition in the electric industry. The SCC believes significantly more evaluation is necessary to determine what, if any, restructuring of the industry may best serve the public interest in Virginia.

Together, the series of SCC orders represents the nest step in the Commission's investigation of current issues related to potential restructuring in the electric industry. The SCC investigation began in September, 1995. On July 31, 1996, the SCC staff filed a 400-page report offering numerous recommendations for SCC consideration.

The SCC directed Virginia Power, American Electric Power and Allegheny Power-Virginia to specifically address six of the 14 recommendations contained in the staff report. These include detailed cost-of-service studies and suggested adjustments for eliminating cross subsidies among customer classes.

Companies also must file sample rates that unbundle generation, transmission and distribution functions; identify ways to improve price signals to customers; determine appropriate reserve margins and how best to meet future needs for capacity; and analyze policies regarding conservation and load management programs. All information was filed by March 1, 1997.

In addition, companies relying on non-utility generation must file a report by June 1, 1997, detailing efforts to restructure their purchased power contracts. The high cost associated with some of these contracts could have a negative effect on current and future rates.

The SCC staff was directed to monitor developments in the wholesale power market and evaluate wholesale competition and its impact on Virginia utilities. The report was due June 1, 1997. By July 1, 1997 the staff is to file a report on electric utility service quality. Finally, by September 1, 1997 the staff is to file a report on the results of retail wheeling experiments and activities in other states.

Washington

In March 1997, the Washington Utilities & Transportation Commission approved the first retail choice pilot project for Washington Water Power. The program would allow residential and commercial customers to choose an alternate power supplier for two years starting July 1, 1997.

In August 1997, Puget Sound Energy of Bellevue, Washington announced plans to launch a two-year customer choice pilot program on November 1, 1997 designed to test customer and supplier related operational issues.

The pilot will be open to residential, commercial and industrial electricity customers. It will run through December 1999 and will be offered to 10% or 85,565 of all Puget customers with a maximum participation level of 10,321 customers, which is 1.2% of the utility's load. Those chosen to participate in the pilot will be located in Bremerton and Mt. Vernon Washington because the markets are contained and suppliers will be able to reach potential customers by advertising in local media.

West Virginia

In February 1997 the West Virginia Public Service Commission initiated a formal investigation into whether and how the state's electric utility industry might be restructured and deregulated to increase competition and reduce electric rates. (Case No. 96-1491-E-GI) A task force was formed to review the restructuring issues relative to West Virginia's economy and present a report to the PSC in October 1997.

In August 1997, American Electric Power and Allegheny Power, investor-owned utilities that serve most of West Virginia, told regulators they do not object to relatively quick implementation of generation competition and retail wheeling and offered suggestions on implementation.

Wisconsin

In February 1996, the Wisconsin Public Service Commission issued a workplan to restructure the electric utility industry. The plan outlined a sequential approach that required certain conditions to be satisfied before a decision could be made on whether full retail access was feasible.

August 13, 1997 the commission revised the workplan shortening the process from 32 to seven steps but still retaining the contingent approach to retail wheeling.

The revised workplan was criticized by several groups. The Coalition for Competition in Electricity questioned why the PSC would establish an independent system operator, seek authority for merchant plants and undertake functional segmentation when the agency has not concluded that the end point is retail competition. The coalition characterized the workplan as "a journey without a destination."

Madison Gas & Electric told the PSC that the most effective way to create a competitive market out of vertically integrated monopolies is to break the industry apart through divestiture. Generation, transmission and distribution functions should rest in separate, unrelated and unaffiliated companies according to MG&E.

The Citizens' Utility Board focused its comments on the serious transmission constraints in Wisconsin. A competitive market cannot develop if suppliers cannot bring the power into the state. Improving and diversifying Wisconsin's capacity situation will take time and will require overcoming the resistance of the largest IOUs, according to the CUB.

Wyoming

In May 1996 the Wyoming Public Service Commission began a collaborative process with all stakeholders interested in electric restructuring issues. As a result of this process the PSC released a White Paper addressing restructuring, November 12, 1996. One of the recommendations in the paper was to conduct a comprehensive study of the economic impacts that electric restructuring might have on the State of Wyoming and its economy.

February 20, 1997 Black & Veatch was chosen to conduct the study. A final report on the study is expected by August 1997. A copy of the report will be available via the commission's website by mid-September, 1997.Sources: This table has been compiled from a variety of sources including Electric Utility Week, Public Utilities Fortnightly and state commission and legislative Internet websites.

SUMMARY OF ELECTRIC UTILITY PILOT PROGRAMS

ILLINOIS

Participant: Central Illinois Lighting Company
Start Date: May 1, 1996
Duration of Experiment: 2 years for large industrial customers and 3 years for others

Project Description:

This pilot program involved all classes of customers. The size of the experiment was limited to 50 MW for the 8 largest industrial customers and 50 MW for all other classes of customers. The industrial customers were limited to purchasing a maximum of 10 MW from other suppliers. For all other customers, the experiment was limited to 5,500 customers in specified locations (e.g., Peoria Heights) that were referred to as "open access sites."

1. 33% of eligible residential customers, 44% of eligible commercial customers and 50% of eligible industrial customers participated in the pilot. About 35% of customers in the pilot program switched from CILCO to other suppliers. CILCO held "educational fairs" to explain the program to groups of customers. Competitors were also invited to provide information.
2. Market research by QST Trading (QST), CILCO's marketing affiliate, concluded that many residential customers would be willing to switch suppliers if they were guaranteed savings. Most customers realized savings of about 20%.
3. Customers are allowed to reduce or totally eliminate their levels of participation upon 24 hours' notice. As of the first quarter of 1997, no customer has asked to be switched back to CILCO.
4. No requirements placed on alternative suppliers beyond registering with the Illinois Commerce Commission.
5. While there were no reliability problems noted by CILCO, they found that competing suppliers tended to provide too much power in order to cover their customers' load requirements.

Comments:

CILCO's two pilot programs, known as "Power Quest," were the first announced experimental electric retail competition programs in the United States. They were also the first programs implemented that were open to all types of customers. The company announced the programs on August 28, 1995 and the pilots began on May 1, 1996. The program allows eligible residential, commercial and industrial customers to purchase power from suppliers outside of the CILCO system (e.g., Cinergy).

After the experiment was initiated, the Citizens Utility Board (CUB) alleged that CILCO and its marketing affiliate QST engaged in anticompetitive activities that were aimed at limiting the involvement of other energy suppliers. Specifically, the CUB contended that QST had about 100% of the market share as a result of their prior knowledge of the location of the open-access residential sites. The two sides were able to negotiate a settlement, in which CILCO agreed to expand the number of residential customers allowed to participate in the program.

Critique:

Interviews with CILCO personnel confirm that the experiment has been a success from their perspective. The 20% average savings, combined with the fact that about 1/3 of all customers chose other suppliers, would indicate this has been a success from the perspective of marketers and customers. The customer participation was particularly high in view of the initial problems involving CILCO's marketing affiliate QST.

SUMMARY OF ELECTRIC UTILITY PILOT PROGRAMS

Participant: Illinois Power Company
Start Date: April 25, 1996
Duration of Experiment: 3.5 years

Project Description:

The "Direct Energy Access Service" pilot program is limited to 21 industrial customers with minimum loads of 15 MW and they must take service at 34.5 kV or above. IP was directed by the ICC to determine if it is feasible to include residential and small commercial customers in a pilot program.

1. The 16 customers participating in the program are allowed to leave the program once or reduce their demand to a minimum of 2 MW.
2. No requirements placed on alternative suppliers.
3. IP provides back-up service in the event that competitors do not provide sufficient power to cover their customers' load requirements. There have been some load imbalance problems.

Comments:

In September 1995, Illinois Power announced their intention to establish an experimental program to allow 21 of its largest customers to purchase up to 50 MW from other suppliers. IP's pilot became the nations' first pilot program to get underway on April 25, 1996. The pilot, known as the Direct Energy Access Service (DEAS), is expected to continue through December 1999.

NEW HAMPSHIRE

Participants: Public Service of New Hampshire (PSNH)
Connecticut Valley Electric
Granite State Electric
Concord Electric
Exeter and Hampton
Start Date: May 28, 1996
Duration of Experiment: 2 years

Project Description:

This pilot program involved all classes of customers, but the size of the experiment was limited to about 50.74 MW. Large industrial customers were asked to volunteer and were then selected at random. Residential and small commercial customers were selected at random and allowed to participate as a group or individually. In total there were 17,000 eligible customers.

1. Only a minimal effort was expended to educate customers through newspaper ads, telemarketing and direct mail and direct contact with sales persons.
2. The rural electric cooperative (NHEC) did not participate due to a dispute with Public Service of New Hampshire over PSNH's promotional program and PSNH's transmission tariff.
3. Customers may leave the program but they can not re-enter the pilot program at a later date. Participants can switch suppliers as many times as they want.

SUMMARY OF ELECTRIC UTILITY PILOT PROGRAMS

4. Competitors must be members of the New England Power Pool or have a contract with a NEPOOL member. The 30 alternative suppliers were required to register with the New Hampshire Commission. New Hampshire utilities could only participate through their independent marketing affiliates.

Comments:

The New Hampshire Legislature required the Public Utilities Commission to establish a pilot program that included all types of customers. On May 28, 1996, the experimental program commenced. Five of the six franchised utilities are participating in the pilot. The New Hampshire Electric Cooperative, serving 66,200 customers, is not involved. While the NHEC expressed some interest in participating, PSNH's transmission rate included recovery of stranded costs, which the NHEC believes the responsibility should be of PSNH rather than alternate suppliers.

The utilities and marketers offered customers a wide range of incentives to participate. PSNH's affiliate, for instance, offered a $25 sign-up bonus and a rate of 3.3 cents per kWh. Northeast Utilities, the parent of PSNH, offered to pay a $10.75 per month basic service charge. NU also charged pilot customers just 1 cent per kWh for the first 600 kWh and usage beyond that was 2.9 cents per kWh. Another NU affiliate offered "green power" and conservation incentives such as low-flow shower heads, energy efficient light bulbs, doormats and hydro-power. ENRON and a few of other marketers offered donations and the guarantee of lower prices to attract municipal customers. Wheeled Electric Power, in partnership with Cinergy, offered power at 2.29 cents per kWh for the first 500 customers that signed up.

Critique:

While there has not been any official report by the Commission, press accounts and industry publications suggest that the pilot has been generally successful. Despite PSNH's very high electric rates, most customers chose to remain with PSNH or one of its parent company's (Northeast Utilities) other affiliates. There were concerns however, that customers did not understand the pilot program.

MASSACHUSETTS

Participant: Massachusetts Electric Company (MECO)

Start Date: January 2, 1997, for residential and commercial (intended to be September 1996)
July 9, 1996, "High Technology Pilot" (for firms in the technology sector)

Duration of Experiment: 1 year

Project Description:

This pilot program involved residential, commercial and high-tech firms. Up to 10,000 residential customers were selected from the cities of Lawrence, Lynn, Northampton and Worcester. The combined commercial and residential sales were limited to 100 million kWh per year. There were 14 high-tech customers.

1. Ballots were sent to all eligible customers who requested information during the "awareness campaign." Of the 10,000 possible, 4,727 are currently participating.
2. Customers could select from lowest price, "green power" or energy supplied with other services.
3. Customers may leave the program but they can not re-enter the pilot program. Participants can switch suppliers as many times as they want.
4. Competitors must be members of the New England Power Pool or have a contract with a NEPOOL member.

SUMMARY OF ELECTRIC UTILITY PILOT PROGRAMS

Comments:

The MECO experiment has a few of innovations that are noteworthy. First, customers selected their energy supplier by ballot that was submitted to an impartial "facilitator." Second, suppliers submitted proposals to provide electricity that emphasized price, green power or energy combined with other services. There were no problems with "load imbalances" since the NEPOOL considers this to be a routine cost of doing business.

Critique:

While the program came close to reaching its maximum size, there was very little initial interest from residential and commercial customers. After the program was extended, the company launched a more aggressive education/public awareness campaign to fill out the program.

NEW YORK

Participant: Orange & Rockland Utilities (O&R)

Start Date: Phase I: July 1, 1996, for large customers
Phase II: January 1, 1997, for residential and commercial customers

Duration of Experience: 3 years

Project Description:

This pilot program initially involved only larger industrial customers and a maximum of 30 MW in Phase 1. During Phase II, up to 1,500 residential and 600 commercial customers were included in the pilot. The pilot was also limited to 40 MW for industrial customers (increased from the original 30MW); 10 MW for commercial; and 3-4 MW for residential. While O&R was permitted to form an affiliate to participate in the program, they declined to do so.

1. Multiple solicitations were sent to a randomly selected group of residential and commercial customers. A sample of 416 customers were chosen. Participants included 59 of the 65 largest customers.
2. Customers have to remain with the program at least one year. They may leave the program after that period but they cannot re-enter the pilot program for another year.
3. Marketers must meet informational requirements established by the state commission. Direct mailings were used to solicit customers, where customers returned a post card if they were interested in participating. The initial response was so low that O&R sent out a follow-up mailing.

Comments:

O&R's "PowerPick" program received such an overwhelming response from industrial customers that they had to conduct a lottery to select customers. In contrast, the response by residential and commercial customers was much lower than expected. This was attributed to a less than concerted effort to explain the program to smaller customers. According to surveys of customers conducted after the initial response, 75% said the savings were not compelling. A large percentage also said that they did not have time to compare the offers.

SUMMARY OF ELECTRIC UTILITY PILOT PROGRAMS

PowerPick allows customers to purchase only energy (no capacity) from alternative suppliers. O&R will continue to provide capacity until 2000, when the program will expand to allow customers to purchase both energy and capacity from alternative suppliers. The company also intends to reorganize into separate generating, transmission, distribution and energy marketing companies. Some load imbalances occurred because marketers did not have "firm" capacity rights on the transmission system.

Critique:

Participation by smaller customers was less than expected, while the participation by the largest customers was so great that the program was expanded to accommodate additional customers. Customers feel that the savings so far have not been substantial as a 17% savings on energy costs only translates into only a 3-5% savings on the total electric bill. Larger customers were concerned with reliability due to regional transmission constraints. It was also noted that customers did not like receiving two monthly bills (i.e., from their selected provider and from O&R for basic service), suggesting that customers might prefer additional unbundling of basic services.

GAS UTILITY ACTIVITIES BY STATE

Class	Significant Actions	Date	Class of Customers Affected
California	Defined core and non-core market segments. Non-core segment allowed to buy unbundled supply and transportation.	1986	Industrial & large commercial
	Statewide capacity brokering plan for allocation of interstate capacity to non-core customers.	11/6/91	Industrial & large commercial
	Adopted rules for a permanent core customer aggregation program that allows small customers to pool together to receive transportation-only service. Pacific Gas & Electric should unbundle its services by 1/1/1998 and Southern California Gas & San Diego Gas & Electric should offer unbundled services by 1/1/1999.	7/19/95	Small commercial
Connecticut	Required firm transport service to commercial customers.	1994	Commercial
	Order addressing cost-of-service methodologies & proposed tariffs for unbundled services. Small customers will not need real-time metering & will be able to choose the level of backup service.	11/2/95	All
Georgia	Public Service Commission issued a policy statement including: unbundling of interruptible service to non-core customers and the establishment of a pilot program for unbundled service to core customers; gradual movement to incentive rates; transition costs should be charged to parties benefiting the most from competition; no cross subsidies between utilities and their marketing affiliates.	5/31/96	Industrial & commercial
Illinois	Northern Illinois Gas, Peoples Gas Light & Coke, MidAmerican Energy Corporation, & North Shore Gas currently offer transportation service.	- - - -	Industrial & commercial
Iowa	Iowa's PUC adopted small customer unbundling in 1986. However, until recently the requirement for telemetering & standby service & a lack of marketers willing to enter the market have prevented effective choice.	1986	Residential
	MidAmerican Energy Corporation conducted a small residential pilot program to unbundle service to all 11/1/95 customers.	11/1/95	
Maine	Unbundling proposal by Northern Utilities under consideration by the regulatory commission.	- - - -	Industrial & commercial
Maryland	Maryland Public Service Commission recommendation to unbundle retail sale service into supply & delivery services for all customers.	11/15/94	Residential & small commercial
	Baltimore Gas & Electric's unbundling filings approved.	8/2/95	All
Massachusetts	PUC approved proposal for a pilot residential unbundling program before the 1996 heating season.	12/31/95	Residential
Michigan	PUC requested comments for LDCs concerning the implementation of small customer unbundling, specifically offering transportation-only service.	2/12/96	To be determined
Minnesota	Minnegasco filed a proposal to unbundle services. Highlights: • Unbundles long-haul pipeline transportation from local delivery • Establishes a 3-year experiment for the aggregation of small transportation customers • In case of a shortage, Minnegasco will make efforts to supply gas to transportation only customers at special rates.	4/14/95	Industrial, large & small commercial
Montana	PUC ordered Montana-Dakota utilities to file a gas - unbundling plan for all customers by July 1, 1996.	- - - -	To be determined

GAS UTILITY ACTIVITIES BY STATE

Class	Significant Actions	Date	Class of Customers Affected
Nevada	Unbundling activity has focused on workshops & issue statements.	----	----
New Hampshire	Transportation offered to customers who consume more than 10,000 therms a month.	----	All
New Jersey	PUC issued guidelines.	1/20/93	Nonresidential
	LDCs required to file plans to unbundle rates to nonresidential customers.	3/29/95	
New Mexico	Transmission, distribution, storage, standby service, and emergency gas service are fully unbundled.	1984	All
New York	New York Public Service Commission (NYPSC) issued general guidelines & asked the largest utilities to file unbundling plans.	12/20/94	Non-core customers (industrial & large commercial)
	NYPSC approved nine plans	3/95	
	Brooklyn Union will offer transportation-only service to commercial & residential customers.	5/1/96	Small commercial & residential
Ohio	Approved a transportation-only rate for schools served by East Ohio Gas.	1/3/94	Small commercial & residential
	Issued a policy statement that expects large LDCs to formulate & implement small commercial & residential programs.	12/1/94	
Oklahoma	Always allowed transportation-only service.	----	Industrial & commercial
Pennsylvania	Equitable Gas filed plans with the Pennsylvania PUC to provide customers in the Pleasant Hills area access to alternate gas suppliers.	Fall 1995	Small commercial & residential. Minimum volume requirement of 5,000 Mcf per year. No more than 10 customers can aggregate to overcome the minimum requirement threshold.
Texas	Always allowed transportation-only service.		Industrial & commercial
Washington	Unbundled sales, transportation, storage, & standby service have been in place since 1989.	1989	----
Wisconsin	Commission endorsed unbundling basic distribution, competitive supply, balancing, peak-day supply, & enhanced services (demand-side management, social programs, etc.).	----	All
	Wisconsin Gas Company began a pilot program of small customer unbundling.		
Wyoming	Scheduled a conference on unbundling.	6/6/95	Proposes unbundled rates only for non-core customers (industrial & large commercial)
	Wyoming Public Service Commission approved KN Energy's unbundled service program for its core customers. Under the proposal, only gas sales would be opened to competition. All other services would continue to be provided by KN Energy.	2/96	All

Source: Energy Information Administration, Office of Oil and Gas, Natural Gas 1996: Issues and Trends, pages 118 & 119.

---- = Not applicable
LDC = Local distribution company
PUC = Public utility commission
Mcf = Thousand cubic feet

Comprehensive Electricity Restructuring Bills

I. Bumpers Bill ("Electric Consumers Protection Act of 1997"--S. 237)
Introduced by Sen. Dale Bumpers (D--AR) in January 1997

A. Mandate for Competition
1. Retail choice required by December 15, 2003
2. Any action taken by a state to promote competition would be grandfathered
3. Sellers of electric service will have reasonable and nondiscriminatory access to unbundled local distribution and retail transmission facilities
4. Customers may aggregate to purchase service as a group

B. State Authority
1. States are responsible for calculating stranded cost for any previously regulated utility that submits an application for recovery
   a. FERC will calculate stranded cost if a state does not do so
   b. nonregulated utilities (munis, co-ops) may calculate their recovery by one of two methods specified by bill
2. States may continue to regulate local transmission and distribution
3. States may impose requirements on any entity seeking to provide service, as long as the requirements are nondiscriminatory
4. States may assess a universal service charge

C. FERC Authority
1. If Congress does not create regional boards to calculate stranded costs for multistate holding companies, recovery falls into FERC jurisdiction
2. FERC will establish transmission regions and designate an ISO for each one
3. FERC will have jurisdiction over mergers that affect retail and wholesale markets

D. PUHCA/PURPA Reform
1. PUHCA would be repealed one year after enactment, but would be replaced with provisions that transfer authority from the SEC to FERC
   a. FERC may exempt holding companies from provisions if each affected state consents
   b. new provisions will not apply if FERC certifies that retail competition exists
2. No public utility is required to enter into PURPA contracts after enactment, or whenever retail competition is implemented in all of its service territories

E. Federal and State Access to Books and Records
1. FERC and states have access to records of holding companies and affiliates deemed relevant with respect to rates, but information is protected

F. Other Provisions
   1. Renewables
      a. each generator's supply must include 5% renewables (including hydro) by 2003, 9% by 2008 and 12% by 2013
      b. FERC will establish National Renewable Energy Trading Program
   2. Retail and wholesale suppliers are granted right to sell to customers of TVA
   3. EPA must report to Congress the impact of competition on air pollution standards

II. Schaefer Bill ("Electric Consumers' Power to Choose Act of 1997"--H.R. 655)
Introduced by Rep. Dan Schaefer (R-CO) in February 1997

A. Mandate for Competition
   1. Retail choice required by December 15, 2000

B. State Authority
   1. States must decide within six months of enactment of bill whether to institute their own retail choice program
      a. nonregulated utilities must also decide within six months whether to establish retail choice
   2. States may assess charges for funding:
      a. stranded cost recovery
      b. universal service
      c. environmental programs
   3. States will put into effect flexible pricing procedures and incentive-based rate regulation

C. FERC Authority
   1. FERC decides which distribution facilities are subject to state jurisdiction
   2. Any state law regarding retail choice enacted after 2000 is preempted by FERC authority
   3. FERC can order a utility to provide transmission service

D. PUHCA/PURPA Reform
   1. PUHCA "ceases to apply" when customers in all states of a holding company's territory have customer choice
   2. PUHCA would be repealed if each state determines that retail customers have nondiscriminatory choice
   3. PURPA is amended to relieve utilities of Section 210 requirements if their customers can purchase service elsewhere on a nondiscriminatory basis

E. Federal and State Access to Books and Records
   1. FERC and states would have access to records of holding companies and affiliates if records are relevant with respect to jurisdictional rates

F. Other Provisions
   1. Renewables
      a. each generator's portfolio must include at least 2% renewables by 2000, increasing to 4% by 2010
      b. FERC will establish a Renewable Energy Credits trading system to help generators meet requirements

III. DeLay Bill ("Consumers Electric Power Act of 1997"--H.R. 1230)
Introduced by Rep. Tom DeLay (R-TX) in April 1997

A. Mandate for Competition
   1. Retail choice becomes effective January 1, 1999
   2. Requires utilities to functionally unbundle T&D from generation
   3. All customers may purchase service from any provider

B. State Authority
   1. States may not impose exit fees or subsidies for stranded cost recovery
   2. States may not regulate prices, terms or conditions of service
   3. States may assess local distribution access charges to ensure that service is provided to residential customers that cannot afford it
   4. States may establish requirements to preserve universal service, maintain reliability, protect consumer rights
   5. States must establish a nondiscriminatory certification process for providers
   6. States must assign a service provider for any customer that does not choose one

C. FERC Authority
   1. FERC will set rates after 1/1/99 if a state has not enacted competitive pricing
   2. FERC has authority to provide for nondiscriminatory prices, terms and conditions of transmission and distribution
   3. FERC must issue rules by 9/30/99 that provide for nondiscriminatory T&D access
   4. FERC will defer to states regarding distribution systems where state authority is granted (Sec. 4--universal service, conservation, renewables, R&D)
   5. FERC must determine by 9/30/99 utilities' market power, and may mitigate by:
      a. restricting sales outside franchise area
      b. ordering divestiture of assets that are source of market power

D. PUHCA/PURPA Reform
   1. Utility is exempt from PUHCA once a state determines competition exists, pending notification to FERC and the SEC
   2. Section 210 of PURPA will no longer apply if competition exists, but existing contracts will not be affected

E. Other Provisions
   1. Thirty months after enactment, FERC must submit to Congress a report summarizing rate reductions, progress of competition and reliability of service
   2. Part II of the FPA will no longer be in effect after enactment of this bill

IV. Thomas Bill ("Electric Utility Restructuring Empowerment and Competitiveness Act of 1997"--S. 722) Introduced by Sen. Craig Thomas (R-WY) in May 1997

A. Mandate for Competition
   1. Does not impose federal mandate to require retail choice

B. State Authority
   1. States may order retail competition if it benefits consumers
   2. States retain jurisdiction over retail sales, and receive jurisdiction over sales to federal facilities
   3. States may establish and enforce performance and reliability standards for sales, marketing and delivery
   4. States may assess charges for funding:
      a. stranded cost recovery
      b. universal service
      c. low-income assistance programs
      d. environmental/renewable energy programs

C. FERC Authority
   1. Removes wholesale sales from federal regulatory purview
   2. FERC is granted jurisdiction over wholesale transmission services
   2. FERC must promulgate final rule exempting specified holding companies (those that hold only QFs, EWGs or FUCOs) from books and records access
   3. SEC authority under PUHCA is transferred to FERC

D. PUHCA/PURPA Reform
   1. PUHCA is repealed
   2. Section 210 of PURPA is repealed
   3. Existing PURPA contracts are to be honored
   4. After date of enactment, no electric utility will be required to enter into new contracts to purchase or sell energy under Section 210

E. Federal and State Access to Books and Records
   1. Each holding company and associate company must make available to FERC books and records deemed relevant to the costs incurred for transmission or energy sales in interstate commerce
   2. Affiliates of holding companies must make available to FERC books and records deemed relevant to costs incurred for any transaction with another affiliate

3. Any company in a holding company system or its affiliates must make available to FERC books and records deemed relevant to costs incurred by such a company
4. Any holding company or its associate or affiliate must produce for state commissions books and records that have been identified in a proceeding before that commission as relevant for the discharge of state commission responsibilities

F. Other Provisions
1. Inspector General of the Treasury must submit to Congress a report regarding the impact of specified utility tax provisions on electric competition
2. Amends the FPA to repeal conflict of jurisdiction guidelines

V. Markey Bill ("Electric Power Competition and Consumer Choice Act of 1997"--H.R. 1960) Introduced by Rep. Edward Markey (D-MA) in June 1997

A. Mandate for Competition
1. No federal mandate for retail competition is established
2. Utilities are prevented from providing service in states open to competition if there is no competition in utilities' service territory.

B. State Authority
1. States must initiate a retail competition rulemaking proceeding
2. States have authority to "opt out" of competition if it is not in state's public interest
3. States have increased power in approving mergers and acquisitions and mitigating market power

C. FERC Authority
1. FERC's approval process for mergers and acquisitions expanded and defined
   a. company seeking acquisition must prove:
      1. no acquisition premium will be recovered in regulated rates
      2. each state involved has certified no adverse effects on retail rates will occur
   b. FERC may then approve merger if it finds:
      1. merger will not adversely affect competition
      2. merger will result in substantial cost reductions
      3. merger will be entered into on arm's-length basis
   c. FERC has authority to establish terms and conditions that maintain provisions necessary for merger approval
2. FERC has increased authority to curb excessive market power, review affiliate transactions and guard against anticompetitive practices
3. FERC will establish regional transmission markets designed to:
   a. ensure development of competitive electricity markets
   b. ensure recovery of prudent transmission costs
   c. prevent "pancaking" of transmission rates

d. prevent nondiscriminatory access to T&D facilities

4. FERC will oversee a newly-created Electric Reliability Council

D. PUHCA/PURPA Reform

1. Utilities may be free from PUHCA and Section 210 of PURPA if a state opens its market to competition
2. PURPA is amended to encourage renewable generation technologies

E. Federal and State Access to Books and Records

1. FERC and states have access to books and records of holding companies and affiliates that are relevant with respect to their jurisdictional duties

F. Other Provisions

1. Renewables
   a. generators must submit to DOE renewable energy credits equal to 10% of sales by 2010
   b. DOE establishes Renewable Energy Credit trading system
2. Universal service
   a. federal-state board is created to review universal service requirements in restructured electricity industry
3. Federal Trade Commission (FTC) is granted authority to issue rules assuring fair disclosure of information
4. President or designee is given authority to issue rules preventing utilities from gaining competitive advantage by owning "dirtier" power plants not subject to pollution standards as new generation sources

VI. Bingaman Bill ("Federal Power Act Amendments of 1997"--S. 1276)
Introduced by Sen. Jeff Bingaman (D-NM) in October 1997

A. Mandate for Competition

1. Does not mandate retail competition
2. Purpose is to facilitate the transition to more competitive and efficient markets for bulk power and to foster the development of state-directed efforts to establish retail competition

B. State Authority

1. Reinforces existing state jurisdiction over bundled retail sale of electric energy and the unbundled local distribution of electric energy
2. Requires states that authorize utilities to provide unbundled local distribution service to ensure the utilities provide distribution service on a nondiscriminatory basis
3. Provides for retail reciprocity. States may bar an electric utility from selling power at retail in the state unless the utility itself is providing unbundled local distribution service

4. Ensures state authority to impose a nondiscriminatory charge on the unbundled local distribution service, retail sale or generation for consumption of electric energy.

C. FERC Authority
   1. Extends FERC's jurisdiction over remaining 22% of interstate transmission systems not currently covered
   2. Extends FERC's jurisdiction over transmission of electric energy in interstate commerce if the energy will be consumed in a foreign country
   3. Extends FERC's authority to regulate (only) transmission services of non-jurisdictional utilities, including TVA, Power Marketing agencies, municipals and co-ops
   4. Limits FERC's authority to order unbundled transmission of electric energy sold at retail only if such sales are permitted or required under applicable state law
   5. Establishes national electric reliability standards under FERC jurisdiction
   6. Authorizes FERC to site new interstate transmission facilities
   7. Authorizes FERC to require participation in an ISO to assure non-discriminatory access to the transmission grid for all parties
   8. Authorizes FERC to draw the line between interstate transmission, which is subject to FERC authority, and local distribution, which is subject to state jurisdiction

D. PURPA Reform
   1. Protects wholesale contracts in that states may not bar a regulated utility from recovering the cost of any PURPA contracts

E. Other Provisions
   1. FERC and the states should ensure that competition does not result in the loss of service to rural, residential or low-income customers.
   2. Allows for the establishment of a regional ISO

PUHCA/PURPA Reform Bills

I. D'Amato Bill ("Public Utility Holding Company Act of 1997"--S. 621)
Introduced by Sen. Alfonse D'Amato (R-NY) in April 1997

A. Repeal of PUHCA
   1. PUHCA is repealed effective 18 months after enactment of bill
   2. SEC authority under PUHCA is transferred to FERC

B. State and FERC Authority
   1. States and FERC retain jurisdiction to determine whether a public utility may recover in rates any costs of affiliate transactions
   2. FERC must issue rules to exempt specified holding companies (those that hold only QFs, EWGs or FUCOs) from providing access to books and records

3. FERC must issue rules exempting any person or transaction from providing access to books and records if regulation of such persons or transactions is irrelevant to jurisdictional rates of a public utility

C. Federal and State Access to Books and Records
   1. Each holding company and associate company must make available to FERC books and records deemed relevant to the costs incurred for transmission or energy sales in interstate commerce
   2. Affiliates of holding companies must make available to FERC books and records deemed relevant to costs incurred for any transaction with another affiliate
   3. Any company in a holding company system or its affiliates must make available to FERC books and records deemed relevant to costs incurred by such a company
   4. Any holding company or its associate or affiliate must produce for state commissions books and records that have been identified in a proceeding before that commission as relevant for the discharge of state commission responsibilities

II. DeFazio Bill (H.R. 1359)
Introduced by Rep. Peter DeFazio in April 1997

A. PURPA Reform
   1. Amends PURPA to establish a National Electric System Public Benefits Fund to provide grants for support of public programs
      a. requires generators to contribute funds in each year equal to one-half the aggregate cost of implementing certain public programs
      b. authorizes states to establish programs and apply for matching funds
   2. Creates National Electric System Public Benefits Fund Board to oversee Fund